California's Carbon Challenge: Scenarios for Achieving 80% Emissions Reduction in 2050

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Disclaimer

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EXECUTIVE SUMMARY

Meeting the State of California's 2050 target of 80% lower greenhouse gas emissions (GHG) from a 1990 baseline is a challenging goal that cannot be met without a portfolio of measures and strategies that span both energy demand and energy supply. This study focuses on energy emissions with the target of reducing energy emissions by 80% relative to 1990 energy emissions.

Meeting the 2050 target requires both a sustained commitment to aggressively develop existing technologies as well as an aggressive and sustained policy commitment to reshape and ultimately transform the state's energy system. The 2050 GHG target for California appears achievable, but requires significant changes in the way we produce energy, deliver energy services, and utilize energy.

Our 2050 "Base Case" energy system has four critical elements:

➢ aggressive energy efficiency across all sectors (at technical potential levels for buildings and industry);
➢ clean or low-carbon electricity;
➢ electrification of vehicles as well as buildings and to a lesser extent, industry heat; and
➢ low-carbon biofuels.

Figure ES-1 shows overall emissions for the base case approaching the 2050 target compared to the reference ("frozen efficiency") case, relying upon large-scale adoption of existing or near-commercial supply and demand technologies. Also shown is the impact of pursuing each required element individually. Any one element on its own is seen to be insufficient and far from meeting the target. All four elements are needed to be close to achieving the target. For example, a cleaner electricity system is required to enable large-scale electrification as a path to reduce emissions. The base case is estimated to have 130 MMt-CO2eq in 2050 or about a 70% reduction from the 1990 baseline of 427 MMt-CO2eq.
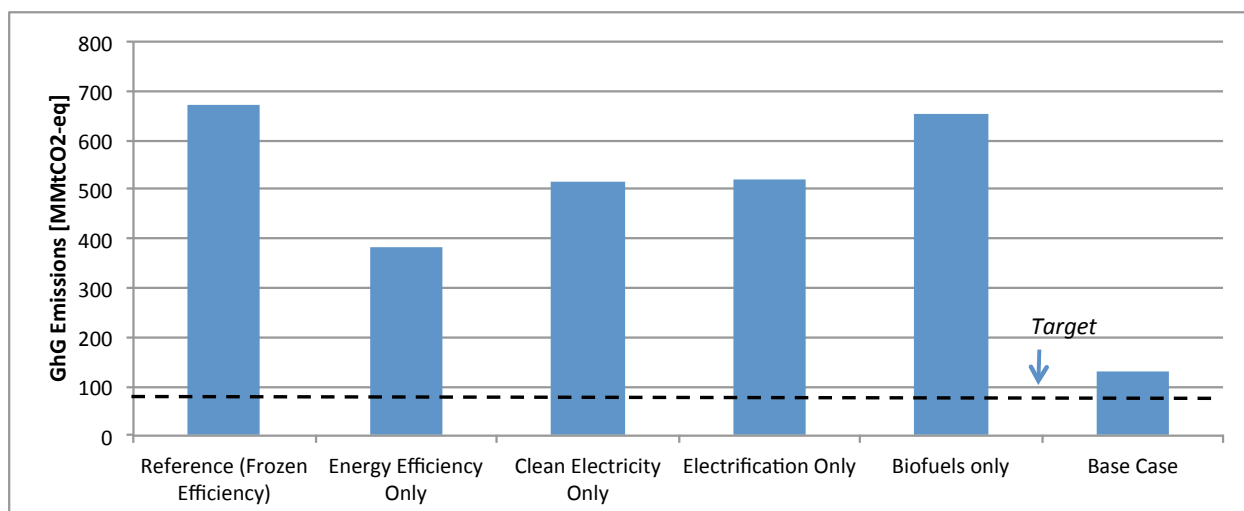
Figure ES-1. *2050 emissions for the Base Case approach the 2050 target. Any one element alone is insufficient and far from meeting target. The base case includes all four elements (technical potential energy efficiency, clean electricity, electrification, and biofuels).*

This report also explores the potential for long-term behavior change to reduce GHG emissions from actions such as changes in driving patterns and dietary habits. About 8-17% of energy emissions savings potential in 2050 are estimated to be from behavior change.

Figure ES-2 shows several scenarios beyond the base case that can meet or come very close to the 2050 target of 80MMt CO2eq for energy emissions, considering additional advances in technology or behavior, such as:

➤ high electrification and high adoption behavior savings (84 MMt);
➤ high in-state biofuels and high adoption behavior savings (82MMt);
➤ biomass power with carbon capture and sequestration with high in-state biomass supply and high adoption behavior savings (79 MMt);
➤ high in-state biofuels and high biofuel imports (74MMt); and
➤ high in-state biofuels and high electrification (71MMt).

The 2050 target can be met with some combination of at least two of the following additional elements: high electrification, high adoption behavior savings, high in-state biofuels, and biomass power with carbon capture and sequestration. Including only one of these additional elements is not sufficient to meet the target.

These scenarios are certainly not the only possible ones to meet the 2050 target but they are attainable within the envelope of known technology. However, to achieve these emissions reductions, sustained technology development is required in each of the four critical areas to both improve performance and/or output and to lower cost. For example, continuous performance improvement and cost reduction are needed in the following:

➢ Energy Efficiency: Technology development in LED lighting for cost competitive replacement of incandescent and fluorescent lighting.

➢ Clean Electricity: Development of lower cost solar electricity; development of viable carbon capture and sequestration from power plants fueled by coal, natural gas, and biomass.

➢ Vehicle Electrification: Improved battery capacity and reliability for plug in hybrid and all-electric vehicles; development of charging infrastructure to support large scale electrification.

➢ Electrification of Heat: Development of electrified heating systems for low temperature industry heating applications. Both vehicle electrification and electrification of heat are predicated on the transition to a much cleaner electricity system.

➢ Low-carbon biofuels: Technology development to increase biomass production on marginal land and to enable high volume production of advanced biofuels at competitive costs to petroleum based fuels.

In addition, high adoption of behavior change would require significant social changes in the way Californians travel, work and consume resources, as well as changes in physical infrastructure. An appropriate policy framework and development of supporting technologies would maximize the potential for achieving behavior changes. For example, more walkable or bikeable communities would reduce demand for vehicle transport.
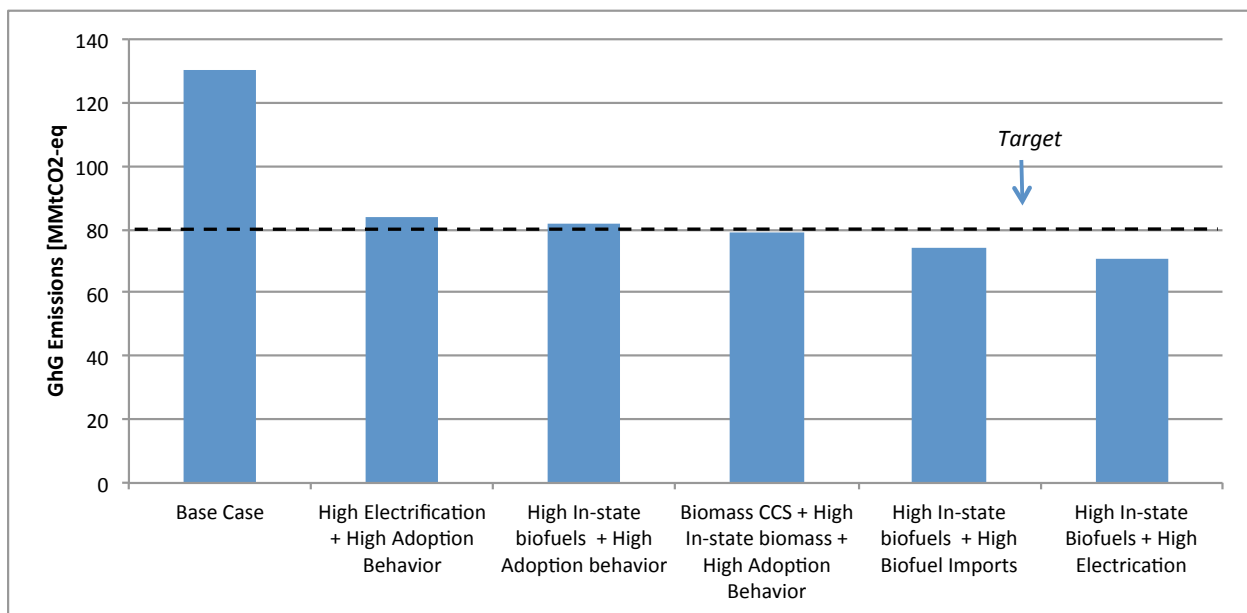

Figure ES-2. *Several scenarios can meet the 2050 target for energy emissions.*

This work also attempts to inject a higher degree of realism into modeling California's future electricity system by using a state-of-the-art optimization tool, SWITCH, to model the entire Western Electricity Coordinating Council (WECC) region, of which California comprises roughly one third. We find that:

➢ The WECC electricity system in 2050 has a diverse set of generation options that can cost-effectively meet aggressive carbon reduction targets.

➢ Projected electricity costs stay relatively constant across a range of possible scenarios in which carbon emissions are capped.

➢ Natural gas is found to be very important in balancing supply and demand on the hourly timescale in power systems with large fractions of energy from intermittent renewable resources.

➢ Natural gas and hydroelectric generators, as well as storage, are utilized extensively to provide sub-hourly load balancing. Sub-hourly load balancing does not appear to be a major limitation to achieving deep carbon dioxide emission reduction in a future electricity grid with up to 60% of energy from intermittent renewable generation.

➢ The coupling of aggressive energy efficiency measures and large amounts of additional demand from vehicle and heating electrification can be accommodated by the electric power system at reasonable cost.

➢ The relative fractions of wind and solar deployment are a function of the temporal characteristics of load, with increasing levels of vehicle and heating electrification favoring wind power over solar power.

➢ Despite their intermittency, both wind and solar power appear poised to supply large amounts of inexpensive, low-carbon electricity to the electric power system of the future.

Overall cost projections to 2050 were not within the scope of the study. The research team developed estimates for 2020 incremental costs versus a "frozen efficiency" reference case and found that overall energy savings in fuel consumption and electricity counterbalanced incremental cost increases for efficiency and electrification. Overall benefits moreover were likely underestimated since health and environmental effects were not included.

An example evolution of the energy demand and overall GHG for the state are show in Figures ES-3 and ES-4, respectively for the high in-state biofuels, high adoption behavior case. Overall energy demand evolution is shown in Fig. ES-3, showing the additive impact of various strategies and separating out fuel and electricity demand. Energy efficiency savings yield 46% savings for fuel and 33% for electricity. Electrification of vehicles and heating increases electricity demand to 7% higher than the reference level but fuel consumption is decreased by one-half with electrification. Adding the base case level of biofuels (3.7 billion gallons gasoline-equivalent) and high in-state biofuels (10 Bgge) partially replaces fossil fuel based liquid fuels, while high behavior adoption further reduces both fuel and electricity demand.

Compared to a reference case with efficiency frozen at today's levels, fuel usage would be decreased by 80% from 2050 reference levels due to efficiency, fuel switching and behavior changes. Forty five percent of passenger vehicle miles would be powered by electricity with passenger vehicle average fuel efficiency above 70 mile per gge (mpgge). In the building and industrial sectors, virtually all water and space heating would be electrified. Low carbon biofuels would contribute significantly to the decarbonization of the transportation sector.

Figure ES-4 shows energy related greenhouse gas emissions in 2050 for energy demand levels including the transition to cleaner electricity. Here, electricity emissions are sharply curtailed from

the reference case with 90% lower carbon intensity due to a mix of renewable and low-carbon power sources, although overall electricity demand is similar. Fuel emissions are seen to take three large downward steps: from energy efficiency, then fuel switching, and then finally in moving to a larger in-state biofuel supply and including high adoption behavior savings. The total emissions for the base case is 130 MMt CO2-eq while for the high instate biofuels and high behavior savings it is 82 MMt, within a few percent of the 2050 target.
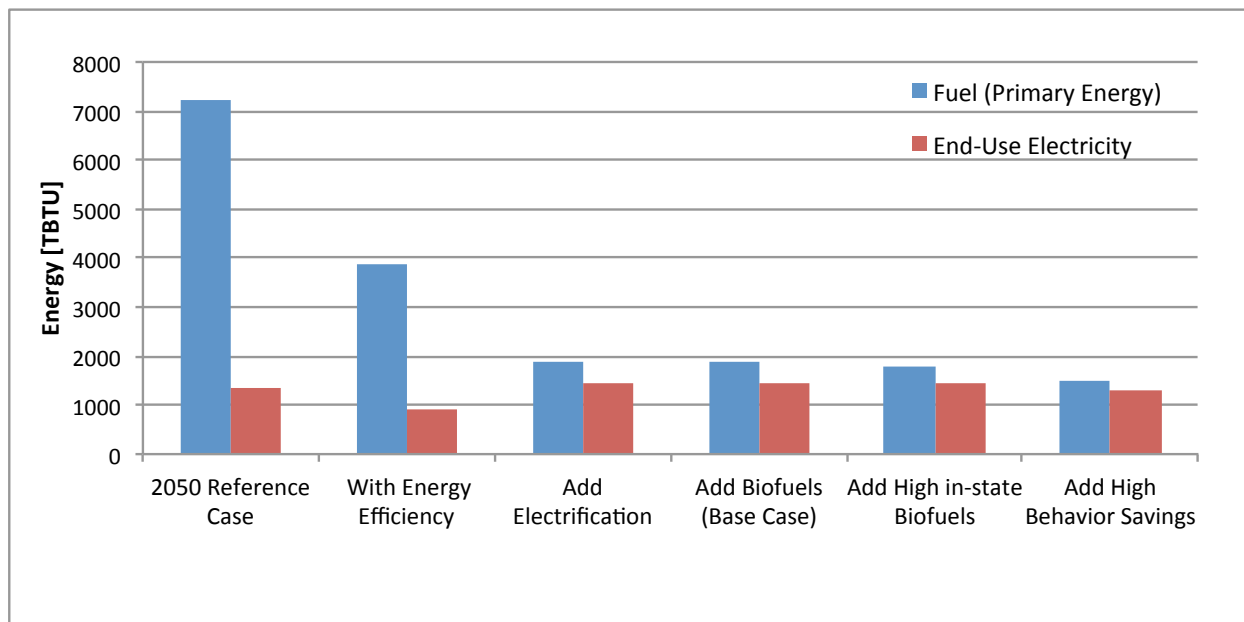
Figure ES-3. *Energy system demand[1] evolution for 2050 base case and with high in-state biofuels and high behavior.*

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[1] End use electricity is shown since primary energy demand for electricity in 2050 will be highly dependent on the actual mix of generation technologies. For reference, the approximate ratio of source to site energy is 3:1 for current grid-based electricity, and if the current mix of generation technologies does not change, primary energy would be three times the end use electricity demand shown here.
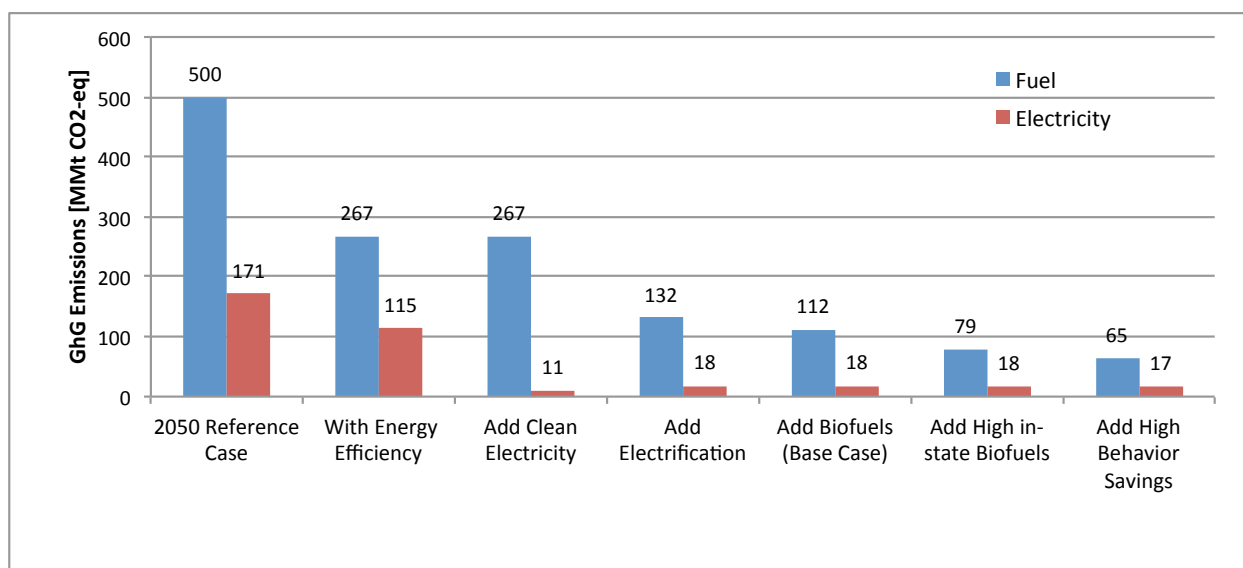
Figure ES-4. *Energy related GHG emission evolution for 2050 including the transition to clean electricity.*

It is critically important furthermore to develop and implement the appropriate policy and market instruments in a timely manner, consistent with meeting the four key requirements, since building and equipment lifetimes are long and the lost opportunity for intercepting new construction or equipment retrofitting may preclude or seriously hinder the prospects for meeting the long term target.

An integrated assessment of base case requirements in terms of technological availability and policy framework is summarized in Table ES-1. From a policy standpoint, California can build upon its policy portfolio to support the long term GHG target (e.g. building codes and standards, EV support, RPS, utility energy efficiency programs). However, electrification of heating appears to be a policy gap, not sufficiently addressed in the state's long term energy policies.

Key Requirement	Technology Availability	Policy Framework	Comment
Energy Efficiency	Many measures commercially available today while other measures need further development	Need aggressive long term targets	Exisiting policies a basis to build continued aggressive targets (utility programs, appliance standards, building codes)
Clean or Low Carbon Electricity	Many technologies commercially available today while some need further development	Need aggressive long term targets	33% RPS in 2020 in place; Need continued aggressive targets beyond 2020 and additional policies to enable consideration of other low carbon sources including CCS and nuclear
Electrification of vehicles	Hybrids commercially available today, Plug-in hybrids and all-electric vehicles in small volume	Need aggressive long term targets	Exisiting policies a basis to build continued aggressive targets
Electrification of heat	Some equipment commercially available today; other equipment and systems need development	No existing policy framework	Paradigm shift with concomitant policy framework needed (e.g. rebate programs for electric appliances, carbon tax on heating fuels, codes and standards, technology development for industry electrification, etc.)
Low Carbon Biofuels	Technologies for high in-state production of low carbon biofuels need development	Need aggressive long term targets	Federal research funding and California LCFS and other policies in place for cleaner fuels; need aggressive targets beyond 2020
Meet 2020 GHGTarget	Mostly commercially available	AB32, Cap and Trade, Others in place	AB32, RPS, LCFS, Cap and Trade, Vehicle emission standards among other policies should enable the state to meet its 2020 target with reasonable confidence
Meet 2050 GHG Target	Technology and manufacturing development needed across first five sectors above	More aggressive policies and targets needed; policy framework needed for electrification	AB32, Cap and Trade, RPS and other policies helpful but not sufficient for 2050.

Table ES-1. *Assessment of technology availability and policy framework for 2050 greenhouse gas targets*.

A policy and regulatory framework and technology development program consistent with meeting the 2050 targets would include the following for maximal chance of meeting the 2050 target:

- Energy efficiency programs that build upon and strengthen existing utility programs, standards, and building codes. Many energy efficiency measures have market penetration and adoption rates which are lower than what is needed (see Section 4 for more discussion). Moreover, current building codes and standards are inadequate to meet 2050 goals and need continuous tightening to meet the 2050 target.
- Continuing to increase automobile fuel efficiency standards and maintaining support for transitioning to cleaner vehicles.
- In industry, a strategy to exploit "low hanging" energy efficiency opportunities.
- Commitment to the 33% RPS target in 2020 and sustained ratcheting the targets upward after 2020 for clean or low carbon electricity, as well as regulatory and technology support for transmission infrastructure and optimal load balancing. To reduce long-term risk and the cost of electricity, the state should include a diversity of low, zero, or negative carbon electricity generation sources in the planning process such as renewable energy, nuclear

power, and carbon capture and sequestration. Appropriate regulatory policies to support these options would also be required.

- Electrification policy and technology development infrastructure to support aggressive building electrification, and technology assistance and development to support electrified heating systems in industry.
- For biofuels, maximal utilization of biomass sources and aggressive development of higher in-state biomass supplies as well as continued support for the development of advanced low carbon biofuels such as cellulosic ethanol. The availability and supply of low carbon biofuels is a key hinge point for future emissions and the amount of the state's and nation's biomass supply as well as the total carbon impact of biofuel production including indirect CO2 impacts will be critical issues moving forward.
- AB32 and carbon trading policy are helpful but insufficient in their current form to meet 2050 targets. AB32 for example is focused on meeting the 2020 climate targets. Nonetheless, existing policies are an excellent basis to build upon, but more aggressive targets and policies in efficiency, electrification and biofuels are needed to achieve the 2050 goal.

Overall Emissions

The overall emissions target in 2050, including both energy and non-energy sources, is 85.4 MMt CO2-eq or an 80% reduction from 1990 GHG emissions. Taking a proportional 80% reduction from 1990 baseline levels of energy and non-energy emissions, the energy emissions target in 2050 is 80 MMt and the non-energy target is 5.4MMt.

Non-energy emissions (non-CO_2 gases such as hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and methane (CH_4)) are projected to be 139MMt in 2050 at current growth rates.   Technical potential savings based on earlier CEC reports can reduce this to 67MMt in 2050. Non-energy emissions are not the focus of this study and are treated separately from energy emissions here. Thus although this study describes several scenarios that meet the energy emissions target of 80MMt in 2050, total projected emissions are almost 80% higher than the overall emissions target. This clearly highlights the need for further reduction strategies for the non-energy GHG emissions.

Purpose and Objectives of this Report

The purposes of this report are to provide the following key outputs:

- Provide an integrated framework/platform in which to model demand evolution and future energy systems using the LEAP modeling framework and a state of the art electricity supply model (SWITCH). The focus is on energy systems, but treatment of non-energy emissions is provided based on previous CEC studies.
- Model and describe scenarios for future energy demand and supply systems that can meet the long term California greenhouse gas (GHG) emissions reduction target of 80% lower overall emissions than 1990.
- Assess the state's ability to meet its 2020 emissions target.
- Provide greater detail in energy demand modeling using bottom up estimates for the building sector in California utilizing and leveraging detailed end use and stock modeling from Itron.
- Provide greater clarity in describing future electricity systems for California in terms of projected supply sources and build out as a function of capital costs, spatial dependencies in demand versus resources and energy resource availability. SWITCH provides greater spatial, temporal and cost detail than previous state studies, and modeling California in the framework of the WECC provides a greater degree of realism than has been done before.
- Inform behavior change adoption estimates and potential GHG emissions reduction from a behavior change model based on bottom up actions and adoption rate assumptions.
- Examine policy/regulatory assumptions and identify key policy area gaps.
- Provide some guidance on incremental cost toward meeting 2020 goals in building efficiency, industry, and transportation. From the SWITCH model, cost estimates through 2050 are also provided for the electricity system.

The report assumes technology that either exists or is soon to exist on the marketplace. It does not focus on policy or market adoption barriers since these have been covered extensively in other studies (e.g. AEF 2009).

Included in this study are incremental cost calculations out to 2020. This study does not address long term cost projections, with the exception of the electricity system. Since the uncertainties in capital costs, technology advancement, economic growth, and fuel costs are large, we do not attempt to project long term costs for the energy economy as a whole, although long term cost projections for the electricity system are provided from SWITCH. For the most part, our energy efficiency adoption rates and energy efficiency potentials are "technical potentials" in that economic costs are not necessarily viewed as limiters to wide scale adoption.

Contents

ABBREVIATIONS AND ACRONYMS

AEO	Annual energy outlook by EIA
ARB	Air Resource Board
BAU	business as usual
BEV	battery electric vehicle
Bgge	billion gallons gasoline equivalent
BTS	Bureau of Transportation Statistics
BTU	British thermal unit
CADOF	California Department of Finance
CALEB	California Energy Balances Database
CARB	California Air Resources Board
CCGT	Combined Cycle Natural Gas Turbine
CCS	carbon capture and storage (or carbon capture and sequestration)
CEC	California Energy Commission
CEF	California Energy Future study
CCST	California Council on Science and Technology
CEUS	California Commercial End-Use Survey
CFL	compact fluorescent lighting
CHP	combined heat and power
CO2-eq	CO2 equivalent emissions
COP	coefficient of performance
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
E3	Energy and Environmental Economics, Inc.
ECF	European Climate Foundation
EE	energy efficiency
EIA	U.S. Energy Information Administration
EUI	unit energy intensity
EV	electric vehicles
FCV	fuel cell vehicles
FERC	Federal Energy Regulatory Commission
FT	Fischer-Tropsch
GDP	gross domestic product
gge	gallon gasoline equivalent
GHG	greenhouse gas emissions
GSP	gross state product
GWh	gigawatt hours
GWP	global warming potential
HEV	hybrid electric vehicle
HFC	hydrofluorocarbon
HVAC	heating ventilation and air conditioning
ICE	internal combustion engine vehicle
IEA	International Energy Association
IGCC	Coal or Biomass Integrated Gasification Combined Cycle

IPCC	Intergovernmental Panel on Climate Change
KWh	kilowatt hours
LCA	life cycle analysis
LCFS	Low Carbon Fuel Standard
LDV	light duty vehicle
LEAP	Acronym for Long range Energy Alternatives Planning System (integrated energy modeling tool)
LED	light emitting diode
Mdt	million dry tons
MMt	million metric tonnes
mpg	miles per gallon
mpgge	miles per gallon gasoline equivalent
MSW	municipal solid waste
MTh	million therms
MWh	megawatt hours
PHEV	plug in hybrid electric vehicle
PIER	Public Interest Energy Research, RD&D division of CEC
PV	photovoltaic electricity
R&D	research and development
RASS	California Residential Appliance Saturation Survey
RD&D	research, development, and deployment
ROW	Rest of WECC
RPS	Renewable Portfolio Standard (mandate for renewable electricity)
SEER	seasonal energy efficiency ratio
SESAT	Scenario-based Energy Savings Assessment Tool (Itron)
SWITCH	Acronym for Solar, Wind, Hydro, and Conventional generators and Transmission (electricity supply system optimization tool)
TBTU	tera BTU
Th	therm
TP	technical potential
TWh	terawatt hours
UC	University of California
UEC	unit energy consumption
VMT	vehicle miles travelled
WECC	Western Electricity Coordination Council

1.   INTRODUCTION

1.1   Background

Recent reports from the Intergovernmental Panel on Climate Change (IPCC) project serious adverse consequences if global temperatures are not stabilized to no more than 2^0C (3.5^0F) warmer than pre-industrial levels (about $1.1C^0$ above present levels).   Over 100 countries have adopted the "2 degree C target." Considering the trends of energy growth and greenhouse gas emissions from the developed and developing world, meeting this target necessitates that industrialized nations reduce their greenhouse gas (GHG) emissions by 80% from 1990 levels by 2050.   Several states in the U.S. including California, Florida, New York and Massachusetts have committed to an 80% reduction by 2050 (Pew 2011).

California has been a leading state in aggressive carbon reduction targets and legislation. In 2005, Governor Arnold Schwarzenegger of California issued an executive order to reduce greenhouse gases to 80 percent below 1990 levels by 2050 (California 2005).   In 2006, the state of California government signed into law AB 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law (2020 emission limit of 427 million metric tons of carbon dioxide equivalent (MMTCO2E) of greenhouse gases).   This is equivalent to reducing 2020 emissions to 1990 levels (ARB 2006).

California has been a leader in energy efficiency standards and building codes dating back to the 1970s. Recently this has been augmented by aggressive renewable energy portfolio targets (33% renewable electricity by 2020) and emission intensity standards for liquid fuels (Low Carbon Fuel Standard or LCFS).

Meeting the 2020 target from AB32 involves implementing many required measures and policies and thus has been the focus of recent planning documents and related policy actions. In 2008 the state released a 2020 scoping plan providing an outline for actions. In 2007, the state passed regulation to require the mandatory reporting of GHG emissions from the largest industrial sources and an emissions trading system ("cap and trade"), currently in intensive discussion and scheduled for deployment in 2012, enforceable in 2013. The state has convened committees to investigate environmental justice (EJAC) impacts and an economic and technology advancement advisory committee (ETAAC) to provide recommendations and guidance for R&D, technology development and reduction measures.   In addition California has passed increased vehicle efficiency standards (AB1493 or "Pavley I") for new passenger vehicles from 2009 through 2016.

There is reasonable confidence the 2020 target can be met. Recent history shows that economic conditions can play a large role in overall emissions and that emissions growth can be slower than anticipated in developed economies especially in light of the 2008-2009 recession and persistent sluggishness in the U.S. economy.   For example 2007 ARB projections for 2020 (ARB 2007) were 596 MMt CO2eq in the business as usual (BAU) case.   But with the recession of 2008-2009, July 2011 ARB projections (ARB 2011) were 15% lower at 507MMT CO2eq (54MMt reduction from the recession and 38MMt for emissions reduction measures (Pavley I automotive standards and 33% RPS for electricity).   With ongoing, adopted and "foreseeable" scoping plan measures to 2020,

emissions in 2020 are projected to be 445 MMt CO2-eq or within 4% of the target. Moreover, "cap-and-trade regulation would establish a declining limit (cap) on 85-percent of statewide GHG emissions. The declining cap established in the regulation would ensure that all necessary reductions occur to meet the 2020 target, even if the estimated reductions from other measures fall short," according to CARB.

The 2050 executive order in contrast is not binding by law and does not include specific requirements that AB32 includes for the 2020 target. It is thus important to consider pathways and scenarios by which the state can achieve its long range emissions targets for several key reasons:

- To assess to what degree the 2050 target is achievable with existing or soon-to-be available technology.
- To identify key technology gaps or R&D research areas that are needed
- To highlight key infrastructure and/or investment areas that need attention
- To highlight required adoption rates and energy savings rates in areas such as building retrofits and new vehicle technology adoption. Since many items such as cars, houses, or factory equipment are long lived durable goods or assets, timely and optimal interception of upgrades cycles can be essential to meet long term goals.
- To ensure that pathways to 2020 are consistent with achieving long range 2050 goals and to highlight if they are not. For example, are there any undesirable "lock-in" effects for 2020 that could preclude meeting the 2050 target?
- Since the 2050 target is four decades away, to assess the potential impact of long term behavioral change on energy demand and GHG emissions.

1.2   California's GHG Emission Targets

California's GHG emission targets for 2020 and 2050 are shown in Figure 1-1 relative to a "frozen efficiency" case. Figure 1-1A includes all emissions from both the energy and non-energy sectors, while Figure 1-1B depicts energy sector emissions only. Overall CARB emission targets for 2020 and 2050 are 427 MMt CO2-eq and 85 MMt, respectively. These represent a reduction in GHG emissions to the 1990 level by 2020 and an 80% reduction from the 1990 level by 2050. Figure 2-1B shows the target for 2020 and 2050 energy emissions are 399MMt and 80 MMt, respectively. These assume a reduction to the level of 1990 energy emissions by 2020 and an 80% reduction from 1990 energy emissions by 2050, respectively. The focus of this report is on energy emissions, although technical potential estimates will be provided for non-energy emissions.
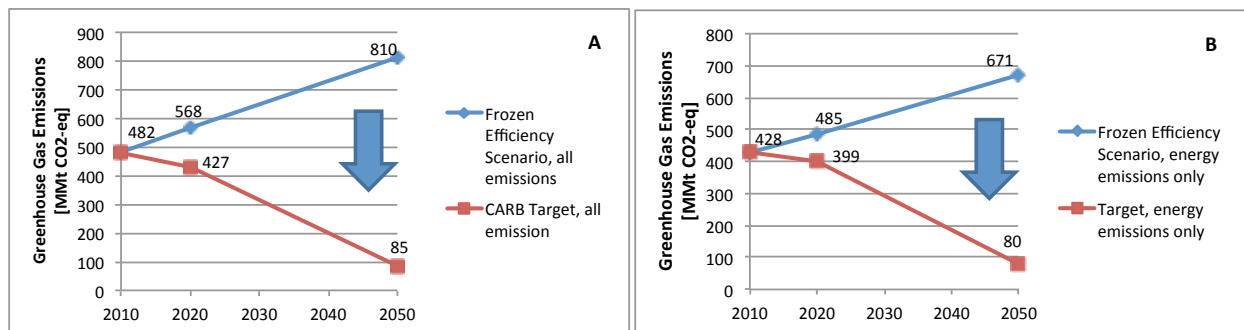
Figure 1-1. *California GHG emissions targets. (A) Overall emissions targets for 2020 and 2050 are 427 MMt CO2-eq and 85 MMt, respectively. (B) Energy emissions target for 2020 and 2050 are 399 MMt and 80 MMt, respectively. These represent GHG reduction to the 1990 level by 2020 and 80% reduction from the 1990 level by 2050.*

We follow CARB conventions for counting GHG emissions, in particular in the transportation sector where some emissions are excluded (e.g. international aviation and interstate aviation).

Our reference case is a "frozen efficiency" case with all future efficiency savings turned off and frozen sales adoption curves of vehicle types. No further fuel switching is assumed and biofuel supply and the renewable fraction of electricity supply are unchanged from current levels. We do not call this case "business-as-usual" (BAU) since it does not include existing and planned policies. However, we adopt this as our reference case since all energy efficiency improvements are calculated relative to a frozen efficiency baseline.

1.3   Study Framework

The framework for this study is similar to other 2050 studies (E3 2009, ECF 2010, CCST2011). Meeting the 80% target requires a radical overhaul in the way energy is supplied and utilized across the state.

First and most critically, aggressive energy efficiency measures are pursued and implemented across all sectors. Energy efficiency is usually the fastest and most cost-effective approach to energy savings and GHG emissions reduction, although this does not imply that it is either fast or cheap to implement. We utilize existing studies for the most part for "technical potential" energy efficiency in the buildings, industry and transportation sectors. Technical potential energy savings assumes technically achievable energy savings with existing technology with less focus on costs.

Second, the electricity supply system is constrained to be largely de-carbonized and able to either meet or exceed its sectoral target of 80% reduction from 1990 since there are a variety of technologies to support this (renewable energy sources such as solar PV, solar thermal, wind and biomass; nuclear power; and fossil fuel power plants combined with carbon capture and sequestration). In keeping with the long-term, technical-potential spirit of this work, we include nuclear power as an option although nuclear construction is currently banned in California. The

legal status of nuclear power could be changed and it is also possible that nuclear plants could be built outside the state and power imported to the state. Technologies used in the electricity sector are selected by minimizing the investment and operating costs of the power system within the de-carbonization constraint.

Together with the de-carbonization of the power sector and the need to meet overall emission targets in all sectors, we also assume that much of the heating sector in buildings and to a lesser extent in industry are electrified through high efficiency heat pumps and/or electrified process heating. This is required in the overall building and industrial heating sector where it would otherwise be technically unable to meet 80% reduction targets.

Finally in the transportation sector, we assume that in addition to efficiency improvements, a significant de-carbonization of transport is pursued through a combination of vehicle electrification and the production of low emission bio-fuels.

We focus on scenarios in year 2050 and pathways toward meeting 2050 targets, including evaluation of 2020 as a discrete year along these pathways, rather than treating 2020 as a separate target or standalone scenario. The reason for this is that our primary objective is to meet long term emissions targets and we would like to avoid a situation where meeting shorter term 2020 goals in any way precludes the state from meeting its 2050 objectives.

1.4   Technology Assumptions

In terms of technology we consider a research and development (R&D) chain as in Table 1-1. For the most part our technology envelope includes "within paradigm" items which exist on the marketplace today or are beyond the demonstration and prototyping stage. For example, known technologies such as solar PV and wind are modeled and included in the electricity supply but enhanced (deep) geothermal is not demonstrated nor proven at reasonable cost or scale and is not included. Heat pump technologies are assumed to be available in buildings but promising "out of paradigm" HVAC technologies such as thermal absorption cooling and novel thermodynamic cycle cooling systems[2] are excluded.

Clearly, there are gray areas; for example basic technology may be known and stage 1 and 2 research and early development been done (Table 1-1), but no products are available. High temperature industry heating is one such example where it is assessed that technologies exist but product development would be needed and this technology application is not included.

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[2] See for example http://www.coolerado.com/

Stage	Technology Development Stage	Building Examples	Electric Power Examples	Industry Examples	Bio-energy Examples
1	Research / Invention / Technology Exploration	Micro recovery of waste heat	Deep Geothermal	Carbon Capture from atmosphere	Artificial photosynthesis for fuel production
2	Early Development/Prototyping		Tidal Power	Process intensification	Algae oils for biofuel
3	Development for Manufacturing	LED lighting for incandescent/CFL replacement	Carbon Capture and sequestration		Advanced biofuels (cellulosic ethanol and alternatives)
4	Deployment and Piloting			Ultra boilers	
5	Low Volume Manufacturing	Heat Pumps for residential space and water heating	Concentrating PV Systems	Membrane separation	
6	High Volume Manufacturing	Condensing furnaces and water heaters	PV, Wind	Variable speed motors	Corn ethanol, Sugar cane ethanol

Table 1-1. *Technology Stages. In general, this report includes stages 3-6 (in development for manufacturing or already in manufacturing) and does not include technologies in the research/invention/technology exploration stage or in early development (stages 1-2).*

We do not consider "breakthrough" technologies that are in the stages of 1 or 2 in research or early development. For example, this might include start-up technologies in cement, new batteries, or novel photovoltaic technology. This area has been a recent focus with private and public investment increasing globally by an average of 30% over the last 6 years (Figure 1-2), and technological progress, development and breakthroughs are expected, but is difficult to model when and in which sector breakthroughs will occur. It may be the case also that technologies are more mature in some sectors than others (e.g. perhaps buildings compared to transportation) and that further energy savings potentials differ beyond the technical potential described.
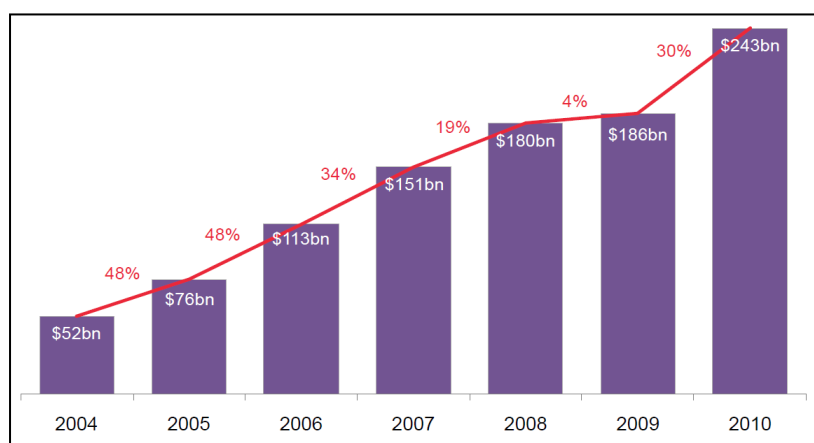
Figure 1-2. *Global new investment in clean energy (Bloomberg 2011)*

We do not attempt to model promising "system integration" concepts that could play a role in reducing energy and material resource demands. These could occur via a number of different avenues.

- Integration of PV and space heating or space cooling (for example: PVT Corp. solar/air heating integration]
- Integration of solar water heating and PV electricity generation
- Solar PV and direct-current (DC) end use appliances
- Waste heat recovery for water heating or space heating

Integrated design is a closely related area that is beyond the scope of this treatment. As championed by Amory Lovins among others (Lovins 1999), integrated design seeks to fully comprehend all system interactions, fully exploit multi-functionality, proper sizing, material re-use, and material efficiency. For example pump systems are most optimally designed with "fat, straight" pipes with the pipe network laid out before equipment placement and sizing. As these design principles take root, we expect further energy efficiency improvements from industry systems beyond the technology-centric efficiency improvements from technical potential studies.

On one hand, we are making the aggressive assumption that technical potential energy efficiencies are achieved and implemented in the building and industry sectors, but on the other hand are not attempting to model the full scope of changes that can plausibly occur in product design and integrated design, system integration, and energy production and manufacturing technology. Indeed one could argue that in the context of a transformation from a fossil-fuel-based economy to an economy based on clean energy and more sustainable production techniques, technical potential studies focused on discrete technologies and end uses may underestimate overall long term energy savings potential.

1.5   Features of this report and comparison with other California studies

The California Carbon Challenge (CCC) project utilizes a bottom-up approach in electricity and building demand. Unlike earlier reports from E3 (2010) and the California Energy Future (CEF) report (CCST 2011), which rely on top-down estimates of building energy efficiency potential, this depiction includes detailed bottom-up estimates of energy efficiency potential based on earlier studies from Itron and the CEC.

For example the E3 report makes top down assumptions such as 50% energy efficiency gains in buildings, full electrification of industry, and does not have bottom up building or industry demand estimates. It also has some estimation for long term costs but costs are not a key focus of the report.

The CEF report also has scenarios presented for 2050. It synthesizes various demand projections and power supply sources in a spreadsheet format, assuming different mixes of technologies and best known "rule of thumb" dependencies on load balancing requirements. The CEF has a similar scenario framework of deep energy efficiency coupled with aggressive electrification of building heat and industry heat. Both this report and the CEF report utilize similar transportation and industry efficiency savings and building and industry electrification adoption rates. Another shared feature with the CEF report is that we assume that the rest of the country and other countries adopts similar measures and GHG reduction plans to California in the long term. For example, we assume that efforts are made to reduce petroleum consumption throughout the

Western Electricity Coordinating Council (WECC) region and beyond through vehicle electrification and increased production of biofuels with lower carbon emissions than conventional gasoline.

In the CCC, we utilize a state-of-the-art electricity supply optimization model, SWITCH, which simultaneously optimizes the operations and build-out of new generation, storage and transmission capacity. SWITCH is a mixed integer linear program that is implemented in this study for the WECC region of North America. The use of SWITCH affords a more comprehensive and realistic integrated projection of future electricity supply and demand. Earlier studies do not consider the interactions between California and rest of the WECC. The E3 study makes the simplifying assumption that some portion of electricity is imported into California along with an a priori assumption of generation capacity build-out and a pre-specified mix of technologies. It has estimates for load shape changes and accounts for load balancing at various time scales based on high level assumptions for storage and backup power requirements. Much greater electricity system detail is provided in this report since it synthesizes bottom-up load shapes and uses the SWITCH model to plan the grid to meet the hourly load. Sub-hourly variation in load and intermittent renewable generation is also accounted for using the SWITCH model's hourly investment framework. The use of SWITCH provides the capability of deriving the electricity supply mix subject to a carbon cap constraint without any top-down assumptions of supply mix and hence provides a "bottom up" modeling capability for load balancing and load following. This study provides a more comprehensive, data-driven picture than is found in the other studies listed above for key issues in the future electricity system such as long-term costs and load balancing requirements with high fractions of intermittent renewable supply sources.

Another unique feature of this treatment is the inclusion of a detailed long-term behavior model. Earlier behavior models focus on short-term behavior potentials, include limited attributes or characterization of behaviors, and provide limited accounting for policy changes or technology changes. This report expands upon other works by moving from the short term to the long term, focusing on habitual actions and extending the set of characterization attributes. The importance of a "behavior wedge" is that a quantification of plausible behavior related savings can reduce the need for additional build out of supply or generation capacity as well as reduce overall emissions.

The team did not perform uncertainty or sensitivity analysis of its scenarios, other than the sensitivity analyses found in the SWITCH model section. Clearly long term projections more than 5-10 years are fraught with uncertainties in fuel costs, economic growth rates (GDP), technological progress, population growth, etc. For example, the recent recession was unexpectedly severe and has sharply curtailed economic growth assumptions and GHG emissions projections in the medium term to 2020-2030. While technology is expected to improve with increasing investment as in Figure 1-1, timing and breakthroughs are difficult to impossible to predict. The scenarios in this report are thus "middle of the road" estimates assuming medium growth rates and predicated on largely known technologies.

1.6 Organization of the report

The modeling approach describing the LEAP model and SWITCH optimization model is described in Section 2. Scenarios toward meeting long term GHG emission targets are discussed in Section 3. All scenarios start with aggressive energy efficiency and electrification of demands. Demand sector projections for building, transportation, and industry are presented in Sections 4-6 and summarized in Section 7, while supply sectors including the electricity sector and biomass are covered in Sections 9 and 10. Non-energy emissions are briefly discussed in Section 8. A long term behavior change model and results are summarized in Section 11. Emissions for each scenario are synthesized in Section 12. Section 13 has a brief summary of incremental cost estimates to 2020. The study concludes in Section 14 and 15 with a discussion of future research directions and summary, respectively. Several appendices provide detail on existing California energy policies, differences between this study and the CEF report (CCST 2011), end use modeling details in the building sector, and additional detail on the SWITCH optimization model.

2. MODELING APPROACH

The structure of the CCC model is shown in Figure 2-1. We utilize two separate modeling tools – one for the power sector and one for non-electricity or fuel sectors. Electricity demand is synthesized from existing sources which is then input into the SWITCH supply model. Non-power sector demands are rolled up into the LEAP model, which is essentially a graphical bookkeeping tool linking bottom-up demands with overall fuel requirements and greenhouse gas emissions.

2.1 LEAP modeling tool

The LEAP modeling tool (Heaps 2008) is used for non-electricity demands and emissions. It provides many features such as the ability to do activity based energy modeling and stock modeling/turnover for equipment and vehicles. It also provides a flexible platform for building new scenarios copied from existing ones or inheriting specified attributes from other scenarios. LEAP also has the capability to model energy balancing of supply sources of fossil fuel and electricity generators although we only use LEAP here to model energy demands and GHG emissions. In the CCC model, there is a supply constraint to the amount of available biomass and imported biofuels and the carbon emissions from the electricity system are capped but there are no supply constraint for fossil fuels such as oil and natural gas.
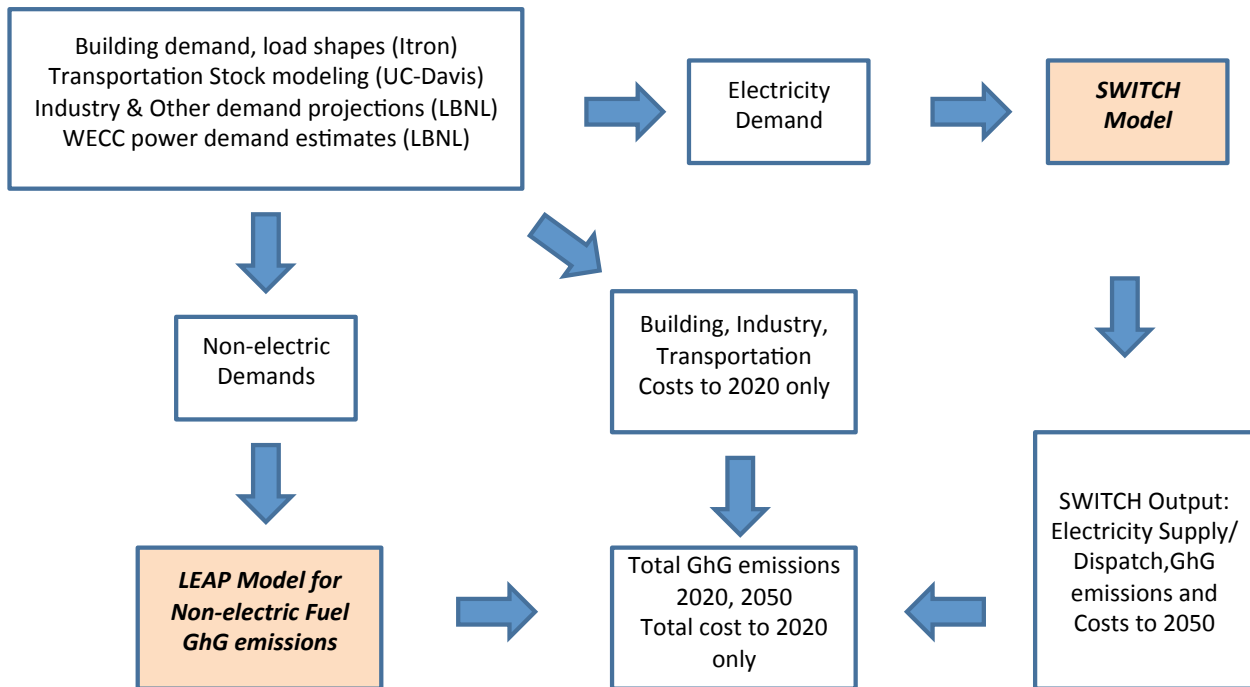
Figure 2-1. *Structure of the CCC Model.*

For buildings and industry fuel demands, we use activity based energy modeling in LEAP based on existing energy efficiency technical potential studies. For transportation, we utilize the stock modeling capability for light duty vehicles, but activity based modeling for the other transportation sectors (trucks, buses, aviation, marine, and rail).

 The energy activity decomposition for buildings end uses (energy services) is as follows:

End use energy of energy service i ~ UEC_i [Annual energy/HH](t) * HH(t) * Saturation Factor

where

$$UEC_i \sim \text{ Energy service * Energy/Service * Usage factor,}$$

$$HH = \text{number of households, and}$$

$$\text{Saturation = fraction of households with the service}$$

For example,

$$\text{UEC (lighting) per household} \sim \text{ [lumens] * [Watts/lumen] * Time of use [hours]}$$

Note that in this decomposition, factors such as fuel switching and behavior can be readily modeled through the saturation factor and usage factor, respectively.

For a given end use or sector, the percentage of fuel type can be assigned in LEAP. For example, electric space heating in single family homes could have an initial saturation of 12% of households with the remaining 88% of households having fuel based space heating, of which 85% is natural gas and 3% other fuels. Over time saturation of electricity and fuels can be modeled to increase or decrease.

The key here is to obtain UEC functions for the population in question (e.g. single family new homes or multi-family existing homes) and the energy efficiency potential for the particular end use. Fortunately for this study we utilize the output of existing energy efficiency studies for buildings, transportation, and industry for UEC values and projected energy efficiency.   For example, we utilize the UEC and energy efficiency data generated by Itron's bottom up stock turnover model for buildings (Itron 2008) and light duty stock modeling data from University of California-Davis (Yang 2009).

Population estimates are based on CEC Department of Finance estimates from 2007 (CADOF 2007) employed in earlier Itron, LBNL, and UC-Davis studies (Masanet 2011, Yang 2009). California population is projected to increase 60% to 59.5 million people by 2050 or 1.18% annually. This is similar to the CEF 2011 study which projects a 55.6 million population in 2050.

Biofuel supply estimates are based on biomass supply estimates for the state from the CEC and Heather Youngs of the Energy Biosciences Institute of the University of California Berkeley (Youngs 2010). Biofuel yield is assumed to attain the current technical potential in gallons of ethanol per

dry ton of biomass by 2050 and a best known LCA emissions factor for biofuel consumption and production is utilized based on EPA estimates (EPA 2009A).

An integrated picture of overall fuel usage and emissions can thus be synthesized over time based on this set of population, households, energy usage data, energy efficiency data, and fuel mixes.

The following sectors are not treated with the same detailed methodology: landfills, wastewater disposal, high GWP gases and agriculture. Emissions from these sectors are included in LEAP and technical potential savings based on CEC reports are applied to 2020 and extrapolated to 2050. Other assumptions for these sectors are discussed in the section below on Non-energy and Agriculture/Forestry demands (Section 8).

We do not model costs using the LEAP model but separately tally short term incremental costs by sector to generate an incremental cost number for meeting the 2020 GHG target.

The LEAP model is static in the sense that it is not currently set up to respond to changes in GDP growth assumptions. Rather, historical data is used to project UEC consumption and growth rates, commercial square footage per capita, miles driven per capita, etc. In this sense the model is a "median case" population growth, "medium growth" GDP case. The model does not include elasticity of response to fuel prices and for the most part, there are no feedbacks between energy supply or demand with industrial output, i.e. a scenario with high PV electricity supply does not impact industrial output. The one exception to this is in the area of transportation fuels. We attempt to capture the electricity demand incurred by increasing production of in-state biofuels. Similarly, as the in-state demand for oil and natural gas is reduced from greater efficiency, higher biofuels and increasing vehicle and heating electrification, we reduce the size of the oil and gas industry in the state proportionate to the reduction in demand.

2.2   Modeling Electricity Demand

California electricity demand modeling primarily utilizes existing studies. Itron building demands, technical potential efficiency for residential and commercial buildings, and new demand from fuel switching are used for buildings. Industry manufacturing demands utilize a PIER 2011 study (Masanet 2011) and the CALEB energy database (De La Rue de Can 2010) is used for other industry demands. Industry fuel switching to electricity is estimated primarily from low temperature process heating. Transportation stock modeling and activity is based on modeling from UC-Davis.

For WECC demand we utilize utility reports (Northwest Power 2010, AESO 2009, BC Hydro 2008) and apply California incremental vehicle and heating electrification demands to the rest of the WECC (ROW). Demands are projected to 2050 based on AEO 2010 projections. We assume the same technical potential savings levels as California for the ROW. Similar vehicle electrification and electrification of heating as California is applied to the ROW but delayed to 10 years after California. More details for WECC demand aggregation will be provided in the electricity demand section (Section 7) below.

By aggregating sector level demands, WECC region annual electricity demands are generated to 2050. These annualized demands are combined with hourly load shapes and are given to the

SWITCH electricity supply model, which will be described below. Combining LEAP model output for non-electric fuel GHG emissions and non-energy emissions and SWITCH output for electricity emissions yield total GHG emissions for California. Carbon emissions from SWITCH are calculated for the entire WECC and as California values are not easily disaggregated, proportional carbon reduction constraints for WECC are assumed to hold true for California. In other words, we assume that an 80% carbon constraint for the WECC in 2050 translates into an 80% carbon constraint for California. This assumption will be more thoroughly validated in future work.

2.3   SWITCH Modeling Tool for Power Sector

We utilize a state-of-the-art electricity supply optimization model, SWITCH, to simultaneously optimize the evolution of new generation, storage and transmission capacity as well as grid operations in the electric power sector. SWITCH is a mixed integer linear program that is implemented in this study for the WECC region of North America. The SWITCH model addresses many of the problems associated with intermittent generation by utilizing time-synchronized hourly load and intermittent renewable generation profiles in a capacity expansion model. SWITCH determines the contribution of baseload, dispatchable and intermittent generation options alongside storage and transmission capacity on a least-cost basis in order to meet projected electricity load while subject to policy constraints. Here, we model the evolution of the electricity grid between the present day and 2050 under a cap on carbon emissions. For most cases in this work, we require an 80% reduction from 1990 emission levels for the electricity sector. Details of the SWITCH model can be found in Section 10 and Appendix 5.

The use of SWITCH affords a more comprehensive and realistic integrated projection of future electricity supply sources and locations across WECC than is present in previous studies. The E3 study makes the simplifying assumption that some portion of electricity is imported into California along with an a priori assumption of generation capacity build-out and a pre-specified mix of technologies (E3 2009). Likewise, the CEF study adopts a top down based mix of electricity supplies for its scenarios (CEF 2011). The use of SWITCH provides the capability of deriving the electricity supply mix subject to a carbon cap constraint without any top-down assumptions of supply mix.

Economic optimization is only done for the electricity system and not for the entire energy system. For most cases in this work, we require an 80% reduction from 1990 levels for the electricity sector emissions. This is consistent with a proportionate contribution to the 80% reduction target for all sectors. An optimization of the entire economic system might lead to different apportionments of emission reductions between sectors. As the electric power sector has many large and potentially inexpensive emission reduction options, future studies will investigate a stronger cap on electricity emissions.

3.   SCENARIOS TOWARD MEETING LONG TERM CLIMATE TARGETS

Several studies have followed the same approach as is taken here for major energy system scenarios (E3 2009, CCST 2011).   The key common features of all of these reports is deep energy efficiency, electrification of building and industry heating, de-carbonization of the electricity sector, some vehicle electrification and a partial transition to a clean transportation fuel supply from greater production of in-state biofuels and importing of out of state biofuels.

3.1   Reference Case

Our reference case is a "frozen efficiency" case with all future efficiency savings turned off and frozen sales adoption curves of vehicle types.   No further fuel switching is assumed and biofuel supply is unchanged from current levels.   This case does not have a carbon cap for the electricity system in 2050. We do not call this case "business-as-usual" (BAU) since it does not include existing and planned policies. However, we still adopt this as our reference case since all energy efficiency improvements are calculated relative to a frozen efficiency baseline. We also consider a frozen efficiency case that does have a carbon cap ("frozen efficiency and electricity cap") for the electricity system in 2050 to see the impact of having a cleaner electricity system but with everything else at frozen levels. All scenarios are described in Table 3-1 below.

3.2   Base Case

The base case includes aggressive energy efficiency, vehicle and heat electrification and 3.7 billion gallons gasoline equivalent (Bgge) per year of overall biofuels in California in 2050 (biomass/biofuels to be discussed further below). The base case uses current default values for technology costs in SWITCH.

For all non-reference cases, efficiency savings are taken at technical potential levels for buildings, industry and transportation. These savings levels will be described in the demand chapters of this report

3.3   Electricity supply

All scenarios except the two biomass CCS cases assume an 80% reduction from 1990 GHG emission levels for the WECC region. The biomass CCS cases assume electricity carbon neutrality in 2050 in the WECC, i.e. overall net emissions in the electric power sector are brought to zero with biomass CCS, a net negative carbon technology. Several variants in the electricity supply are modeled, including a high renewable case, high nuclear case, a high CCS case, a no CCS case, a no CCS and no new nuclear case, and an expensive solar photovoltaics case. These are modeled by separately adjusting the cost trajectories of each of these technologies either downward or upward over time from their baseline trajectories, or by entirely excluding certain generation options. More detailed assumptions for the electricity supply are found in the chapter on electricity supply modeling (Section 10).

Scenario	Efficiency	Electrification of Heating and Vehicles	Electricity Supply (SWITCH)	2050 Carbon Cap for Electricity [% reduction from 1990 Emission Levels]	In-State Biomass	SWITCH biomass supply curve [Mdt]	Biomass for fuel [Mdt]	Instate Biofuel [Bgge]	Imported biofuel [Bgge]
Frozen Efficiency	Frozen Efficiency	BAU	Without carbon cap	N/A	BAU				
Frozen Efficiency + Electricity Cap	Frozen Efficiency	BAU	With carbon cap		BAU				
Base case	Tech. Potential	Median (Base case level)	Base case	80%	Low, for liquid fuel	0	35	2.8	0.93
High Nuclear			Inexpensive nuclear		Low, for liquid fuel				
High CCS			Inexpensive CCS		Low, for liquid fuel				
No CCS or New Nuclear			No CCS or New Nuclear		Low, for liquid fuel				
No CCS			All CCS excluded		Low, for liquid fuel				
High Solar and Wind			Inexpensive solar and Wind		Low, for liquid fuel				
Expensive Photo-voltaics			Expensive Photo-voltaics		Low, for liquid fuel				
Biomass CCS			Biomass CCS	100%	Low, for electricity	23	12	1.0	0.3
Biomass CCS + Hi in-state biomass			Biomass CCS	100%	High, for electricity and liquid fuel	23	71	5.7	1.9
High in-state biofuels			Base case	80%	High, for liquid fuel	0	94	7.5	2.5
Hi in-state & High imported biofuels					High in-state + High imports, for liquid fuel				7.5
High Electrification		High	Base case	80%	Low, for liquid fuel	0	35	2.8	0.9
High Electrification & High in-state biofuels		High			High, for liquid fuel		94	7.5	2.5

Table 3-1. *CCC scenarios and assumptions for each scenario.*

3.4   Electrification

All but the last two scenarios assume "base case" electrification of vehicles and building and industry heat described in the transportation, building and industry chapters. The last two scenarios assume a higher degree of vehicle and industry electrification but keep the same level of building electrification.

3.5   Biomass CCS and Biofuels

Biomass supply and bio-energy technologies constitute a key hinge factor in future energy systems. Biomass can be used in stand-alone biomass power plants, power plants that co-fire biomass and fossil fuel, or biogas power plants. Biomass can also be used for making transportation fuels such as ethanol, cellulosic ethanol or other advanced biofuels. Bio-refineries for biofuels can produce electricity as one output. Biomass can also offer the technical possibility of negative carbon emissions in the case of biomass based power generation coupled with carbon sequestration and capture of combusted biomass CO_2.   Further uncertainly is added when considering future technology progress.   Technologies such as algae based fuels or hypothetical artificial photosynthesis can offer further supply or technology pathways toward producing transportation fuels.

Other studies [E3 2010, CCST 2011] have earmarked biomass supply primarily for biofuel production since there is no shortage of technologies that can produce clean electric power and we adopt this approach here.   With the exception of two of our scenarios, all biomass is directed to the production of biofuels and is not made available to the power sector modeling in SWITCH. We consider two cases, biomass CCS and biomass CCS with high in-state biomass supply, where biomass is made available to SWITCH in conjunction with a deep carbon reduction in the power sector from carbon capture of combusted biomass.   As SWITCH optimizes for the cost of electricity, biomass cost projections are needed to correctly include biomass in the model. For the two biomass CCS cases, the 23 Mdt of biomass supply available to the power sector draws on data from existing supply curve projections (University of Tennessee 2007, Parker 2011). Any residual biomass not included in the SWITCH supply curve is made available for biofuel production: 12Mdt in the biomass CCS case and 71Mdt in the biomass CCS high in-state biomass supply case.   For all other cases, where biomass is dedicated to liquid biofuel production, we either take the in-state biomass supply as the cost curve based supply plus of 23 Mdt plus additional municipal solid waste (MSW) sources (yard wastes, food, and construction debris) and energy crops (overall 35 million dry ton biomass supply); or we adopt a "high in-state" biomass supply by taking the technical potential biomass supply for the state based on the CEF 2011 study (overall 94 million dry ton biomass supply).

As an additional constraint, imported biofuels are limited to 25% of total instate biofuels per Executive Order S-06-06 (2006), except for one case which allows a higher level of imported biofuels.   This is in keeping with the vision of a future energy system with less dependence on imported liquid fuels. A fuller discussion of biomass supply assumptions is provided in the biomass supply section later in this report.

Finally, behavior savings with sensitivities for a nominal adoption case and a high adoption case are estimated for each scenario.

4. DEMAND SECTORS AND PROJECTIONS

4.1 Macroeconomic Assumptions

We assume the population grows to 59.5 million residents in 2050 per California Department of finance projections (CADOF 2007). Industry fuel energy growth is assumed to be 0.6% per year and industry electricity growth 1.4% annually as described below in the industry demand discussion. Other key macroeconomic drivers and sensitivities are adopted from a related PIER study (Masanet 2011) and discussed in great detail there, so the reader is directed to that report for the assumptions made regarding housing stock and commercial floor stock growth to 2050. Our approach is to take the "medium-growth" assumptions based on that study.

4.2 Buildings Sector

In this section we present and describe the methodology, data, and assumptions used to forecast total electricity demand from the buildings sector in California. We then present the two primary demand scenarios developed for this study – a "maximum energy efficiency" scenario based on current estimates of long-term technical potential and a "maximum energy efficiency and electrification" (base case) scenario based on both technical potential for energy savings and fuel-switching away from natural gas towards electricity in the buildings sector. We first present the overriding policy assumptions represented in these scenarios and then summarize the key characteristics of the resulting electric load forecasts for the buildings sector.

Natural gas demand in the building sector, fuel usage, energy efficiency and residential/commercial growth estimates were also adopted from the 2011 PIER study. Natural gas demand by end use and sector is tracked in LEAP. For the maximum energy efficiency and electrification (base case) scenario, end use saturations are adjusted to follow the electrification assumptions described below to calculate remaining fuel demand. The focus of this chapter, however, is on the electricity sector.

4.3 Load forecasting approach

The load forecasting approach for buildings seeks to leverage the methods, data, and findings from the latest bottom-up and long-term potential studies conducted for the buildings sector in California. To do this, the research team built upon a spreadsheet modeling tool developed previously for a related PIER study (Masanet 2011) that assessed energy savings potential in California's buildings sector to year 2050. This spreadsheet tool, referred to as the Scenario-based Energy Savings Assessment Tool (SESAT), builds directly upon the detailed data, analysis, and results of Itron's most recent bottom-up assessment of energy efficiency potential in California's buildings sector over the mid-term (i.e. through 2025) and allows exploration of a variety of longer-term outcomes driven by technological change, structural change, and changes in end-use energy service demand that are often beyond the scope of shorter-term load forecasts.

Below we provide an overview of the scope, methods, data, and assumptions used in the 2011 PIER study and summarize the modifications and additions to that analysis that were made for this study.

Overview of 2011 PIER study

The goal of the 2011 PIER study was to develop and apply modeling frameworks to estimate energy efficiency potentials for electricity and natural gas end uses in California's residential buildings, commercial buildings, and industry through the year 2050. To do this, the study team developed separate end use efficiency potential models for California buildings and industry using best-available information and data. The buildings and industrial sector models were constructed using a hybrid modeling approach, which coupled bottom-up, technology rich end use models for the mid-term analysis period (defined in this project as the period 2007-2025) with more aggregate and stylistic models of end use efficiency for the long-term analysis period (defined as the period 2026-2050). These models were designed to estimate the technical potential for energy efficiency improvements, which can be thought of as a theoretical benchmark of the upper bound of energy efficiency potential in a technical feasibility sense, regardless of cost or acceptability to customers.

SESAT modeling framework

One of the primary objectives in developing a forecasting tool for the 2011 PIER study was to leverage, to the furthest extent possible, the detailed data, analysis, and results of California Energy Efficiency Potential Study (referred to hereafter as the 2008 Itron potential update study) – see Itron (2008).[3] The 2008 Itron update study incorporated the latest estimates of baseline end-use equipment ownership and end-use load profiles, along with the latest estimates of efficiency measure costs, savings, and saturation across the service territories of California's four IOUs in order to assess the potential savings, cost-effectiveness (from both a utility and customer perspective), and likely adoption via utility rebate programs of over 200 energy efficiency measures commercially available in California.

An important modeling assumption embedded in the results of the 2008 Itron update study is that there are no significant changes in the suite of energy efficiency measures currently available over the short- and mid-term. Over the short-term, this assumption is reasonable. However, the validity of this assumption decreases significantly over the mid-term (e.g. 2025) and long-term (e.g. 2050) analysis periods. To this end, the approach developed for the 2011 PIER study built directly upon, but was not limited to, the results of the 2008 Itron update study.

Specifically, the research team developed a spreadsheet modeling tool, referred to as the Scenario-based Energy Savings Assessment Tool (SESAT), that uses the results of the 2008 Itron update study as the primary starting points for exploring alternative technology scenarios as well as

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[3] The Itron 2008 potential update study was funded by California's four IOUs with the primary objective of forecasting the short-term (defined as 2016) and mid-term (defined as 2026) gross and net achievable market potential resulting from the installation of energy efficiency measures rebated through publicly-funded energy efficiency programs.

scenarios that explore the impact of macroeconomic and structural changes on long-term energy efficiency potential in California's buildings sector. The research team designed SESAT to introduce the following dimensions into the analysis of efficiency potential over the long-term:

- Interaction and comparison of the impacts of different sets of assumptions (i.e. scenario analysis) in a systematic, transparent, and internally-consistent fashion;
- Exploration of the impact of alternative baseline assumptions (e.g. relative increases or decreases in energy service demand); and
- Assessment of efficiency potential that may exist outside of the current suite of technologies commercially available in California.

Another important aspect of SESAT is that the inputs, outputs, and principle calculations are organized at the end-use level by building type, vintage (i.e. existing vs. new construction), and climate zone (residential only) as shown in Table 4-1 below. The research team chose this level of detail in order to explicitly frame the analysis in terms of end-use market segments for which electricity and natural gas consumption are reasonably well understood. This approach avoids the uncertainties associated with forecasting measure-specific characteristics over time, while maintaining a level of technology detail that is meaningful and relevant for policy and planning.

In SESAT, total energy use is calculated in a bottom-up fashion as the product of end-use energy intensities (e.g. kWh/household or kWh/ft2), end-use equipment saturations, and the number of households (residential) or floor area (commercial) by building type. The primary calculations for total residential and commercial energy use are shown below:

$$Total\ residential\ energy\ use\ = \sum_{ij} UEC_{ij} * SAT_{ij} * HH_j$$

$$Total\ commercial\ energy\ use\ = \sum_{ik} EUI_{ik} * SAT_{ik} * FloorArea_k$$

where:
i = end use
j = residential building type
k = commercial building type
UEC = unit energy consumption by end use i in building type j (kWh/household)
SAT = end-use saturation (%)
HH = total number of building type j
EUI = unit energy intensity by end use i in building type k (kWh/ft2)
$FloorArea$ = floor area of building type k (ft2)

Segment Name	Segment Definitions	
Sector	Residential	Commercial
Geographic region	16 standards climate zones	Statewide
Building type	Single-family dwelling Multi-family dwelling	College Food Store Health Large Office Lodging Miscellaneous Refrigerated Warehouse Restaurant Retail School Small Office Unrefrigerated Warehouse
Building vintage	Existing construction New construction	Existing construction New construction
End use	Space Cooling Space Heating Furnace Fan Water Heating Cooking Refrigerator Freezer Clothes Dryer Lighting Pool Pump Miscellaneous	Space Cooling Space Heating Ventilation Water Heating Commercial Cooking Refrigeration Exterior Lighting Interior Lighting Office Equipment Miscellaneous

Table 4-1. *Summary of SESAT analysis segmentation*

To allow explicit analysis of energy efficiency potential, the research team further disaggregated the UEC and EUI variables so that the impact of changes in technical efficiency due to the installation of efficiency measures can be examined and tracked separately from impacts due to changes in energy service demand (e.g. hours of use). To do this, the team introduced two dimensionless factors that represent the technical efficiency and energy service demand components, respectively, of end-use energy consumption into the principle energy use identity. This relationship is shown below, using residential UEC as an example:

$UEC_{ijy} = UEC_{ijbase} * EffAdj_{ijy} * UseAdj_{ijy}$

where:

UEC_{ijy} = unit energy consumption for end-use i in building type j in year y

UEC_{ijbase} = unit energy consumption for end-use i in building type j in the base year

$EffAdj_{ijy}$ = technical efficiency for end-use i in year y relative to technical efficiency in base year (defined as 1.0 in the reference scenario)

$UseAdj_{ijy}$ = energy service demand for end-use i in year y relative to energy service demand in base year (defined as 1.0 in the reference scenario)

In this analytic framework, any of the variables described above could be treated as parameters in a scenario analysis.

In the 2011 PIER study, the base-year (i.e. 2006) values for end-use saturations, UECs, EUIs, and end-use load shapes by building type were derived from the most recently available statewide building end-use studies conducted in California, namely the *California Statewide Residential Appliance Saturation Study* (KEMA, 2004), and the *California Commercial Building End-Use Survey* (Itron, 2006). The base-year values for residential building stock and commercial floor stock by building type were derived from the most recently available building and floor stock estimates developed by CEC staff for use in the *California Energy Demand 2008-2018, Staff Revised Forecast* (CEC, 2007).[4] The bottom-up estimates of total electricity consumption and natural gas consumption were then calibrated to the respective base-year values published by the CEC.

Assessment of technical potential over the mid- and long-term

To develop the end-use energy savings inputs for the assessment of technical potential over the mid-term (through 2025), the study team primarily leveraged the detailed analyses of over 200 unique efficiency measures reflected in the 2008 Itron potential update study.[5] These detailed, measure-level results were then aggregated to the end-use level in order to calculate the technical efficiency factors described above. Over the 2050 timeframe of the long-term analysis, however, the amount of information available on emerging and future technologies is too limited to extend this level of measure-specific detail and analysis.

In order to effectively leverage the more limited amount of information available on future technologies, the study team developed an approach that first decomposed end-use energy intensities (e.g. kWh/household or kWh/ft2) into multiple discrete, multiplicative components. The

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[4] In order to develop housing and floor stock estimates through 2025 and 2050 (which is beyond the CEC's load forecasting horizon), the research team developed an algorithm to project housing stock and commercial floor stock that leverages the long-term population forecasts produced by the California Department of Finance (CADOF, 20062007). In this algorithm, the historical relationship between population growth and annual housing stock additions is combined with the CADOF population projections to produce long-term housing stock forecasts. In the case of commercial buildings, the historical relationship between total population and total commercial floor stock by building type is combined with the CADOF population projections to produce long-term commercial floor stock forecasts.

[5] The full list and descriptions of the energy efficiency measures included in the 2008 Itron potential update study are available at:

http://www.calmac.org/startDownload.asp?Name=PGE0264_Final_Report.pdf&Size=5406KB

generalized form of these end-use energy intensity decompositions is presented below (commercial electric example).

*End-use intensity (kWh/ft2) = (kW/energy service delivered) * (energy service required/ft2) * (hours of operation)*

In this decomposition, the first term (kW/energy service delivered) describes the efficiency of the end-use equipment, e.g. fluorescent lights, chillers, or water heaters. The second term (energy service required/ft2) describes the amount of energy service (e.g. lumens of light or tons of cooling) required per square foot of commercial building space or per residential home. The third term (hours) describes the operational pattern of the end use equipment. Potential changes in end-use energy intensity can in turn be expressed as changes in the specific individual terms shown above.

For purposes of assessing technical potential, these changes in the individual components of end-use energy intensity reflect three distinct types of efficiency strategies:

- Changes in kW/energy service demand reflect improvements in the technical efficiency of end-use equipment (e.g. replacing fluorescent tubes with LEDs);
- Changes in energy service/ft2 reflect reductions in energy service requirements (e.g. reductions in cooling load from improvements to the building envelope);
- Changes in hours reflect reductions or optimization of operating hours (e.g. matching lighting operation to ambient light through advanced day lighting sensors and controls).

This decomposition approach allows savings estimates to be developed in a way that minimizes double counting of potential savings across multiple efficiency strategies that target the same end use. More importantly, however, this decomposition approach allows the study team to focus on developing savings estimates for more general (but still end-use specific) efficiency strategies and use the more limited information of specific future technologies as representative benchmarks for corresponding efficiency strategies.

Within this end-use intensity decomposition framework, the team developed high/mid/low ranges of plausible 2050 savings values for each efficiency strategy. These 2050 end-use savings estimates were designed to reflect savings that are incremental to the savings estimates developed for the 2025 analysis. These ranges were developed primarily from a series of interviews conducted with technology experts and supplemented with secondary data from technology-specific literature on long-term savings potentials. Once the study team had compiled a full set of strategy-specific savings estimates, the team used a simplified Delphi process to vet and revise the savings estimates among technology experts and team members.

Appendix 3 describes the inputs and assumptions used to develop the long-term technical potential analyses for California's buildings sector.

4.4 Modifications for Current Study

For this study, the research team made a host of modifications and additions to the long-term technical potential analysis developed for the 2011 PIER study. These modifications were driven by both the efficiency-related research objectives of this study and the need to integrate the long-term demand forecast results with the supply-side planning model (SWITCH) in order to enable system-wide modeling of GHG emissions. Specifically, the modifications made to the 2011 PIER analysis included the following: 1) minor revisions to the baseline end-use data; 2) adding the temporal and spatial resolution in SESAT necessary to feed SWITCH (annual electric energy consumption, hourly load profiles, and climate zone-level segmentation); and, 3) adding a demand-side electrification scenario. Each of these modifications is described in more detail below.

Baseline data revisions

In the time since the 2011 PIER study was completed, the results of the *2009 California Residential Appliance Saturation Survey* (KEMA, 2010) became publically available. The electric end-use UECs from the 2009 RASS were used to verify the baseline UECs in the SESAT model for this study. In two specific cases, this verification and comparison process resulted in the research team making adjustments to the baseline UECs in SESAT model based on the 2009 RASS results.

For residential electric space heating, the 2009 RASS results were used to adjust the previous baseline UEC estimates downward. The result of this downward adjustment is that the target year (i.e. 2050) UECs for electric space heating in the technical potential scenario are now consistent with super high-efficiency heat pumps (e.g. 17+ SEER) and tight building shells.

For residential electric water heating, the comparison of previous baseline UECs used in SESAT with the 2009 RASS results identified significant double-counting in the previous water heating UECs associated with clothes washers and dishwashers. After eliminating this double-counting, the revised UECs were then verified with both the 2009 RASS results and metered results from a recent survey of Florida homes (which are nearly all electric) conducted by Itron.

Add annual results

In the 2011 PIER study, the research team developed technical potential estimates for two specific points in time, 2025 and 2050. For this study, however, the research objectives required annual streams of results for electric energy consumption. The research team therefore modified SESAT to produce an annual stream of energy consumption results between the base year (2006) and the target year (2050).

This was accomplished by applying "implementation curves" at the end-use and building type level. These implementation curves reflect the annual changes in average end-use UECs from the adoption of energy efficiency measures. The assumptions and calculations that determined the shape of each implementation curve are described in section 4.5.

Add hourly load profiles

Perhaps the most significant addition to SESAT made for this study was the introduction of hourly load profile information into the model specification. This addition was necessary due to the need to integrate the long-term demand forecast results with the supply-side planning and dispatch model (SWITCH). Since SWITCH, like all planning and dispatch models, is sensitive to the temporal distribution of aggregate electricity demand, it was necessary to expand the temporal resolution of the SESAT analysis.

To do this, the research team expanded the SESAT modeling identity to include load shape information (i.e. the distribution of demand across the day, week, month, and year) as a baseline input at the end-use and building type level. Including load shape information at the end-use level allows changes in the mix of end-use demand (whether from increased energy efficiency or changes in end-use service demand or both) to be transparently reflected in the overall temporal distribution of total load.

For this study, end-use load shapes were developed for each residential and commercial end-use and building type specified in SESAT. For residential buildings, the research team derived end-use load shapes from a set of building simulations performed for prototypical California homes using Itron's *SitePro* simulation software. The load shapes for residential HVAC were differentiated for each of California's 16 forecasting climate zones based on the results of simulations using climate-zone specific weather data. The load shapes for residential electric space heating were further refined by blending the results of two separate sets of simulation results that reflected distinct technology choices – furnaces and heat pumps. The final load shape for residential space heating is intended to reflect the higher COP of heat pumps as well as the heating requirements of tight building shells.

For commercial buildings, the research team applied hourly end-use load shapes by building type from the latest CEUS study (Itron, 2006). Note that the research team made no attempt to differentiate commercial HVAC load shapes across climate zones. This decision was based on the fact that commercial HVAC demand tends to be dictated largely by internal gains (lights, people, office equipment, servers, etc.) rather than external conditions and is thus only weakly correlated to climate (e.g., heating and cooling degree days).

Add climate zone-level segmentation

In order to reconcile the spatial resolution of the SESAT and SWITCH models, the research team also modified SESAT to output results at the climate-zone level. For the residential sector, this was enabled simply by eliminating an aggregation step in the model's reporting function, since all of the inputs were already specified at the climate zone level. In the commercial sector, however, all of the inputs are specified at the statewide level (by building type). In order to generate results for commercial buildings at the climate-zone level, the research team used climate-zone specific floor area data from the 2006 CEUS to share out the building-type level statewide results produced by SESAT across climate zones. These climate-zone and building-type specific results were then re-

aggregated across building types to produce climate-zone level total load forecasts for commercial buildings.

Add fuel switching scenario

Finally, the research team developed an additional scenario that was not explored previously in the 2011 PIER study – the effect of fully electrified buildings. To do this, the research team used the saturation variable in the SESAT modeling identity as a scenario parameter to simulate the load impacts of fuel switching away from gas and towards electricity in the buildings sector. The specific assumptions used to develop and implement the fuel-switching scenario are described further in section 4.6 below.

4.5   Maximum Energy Efficiency Scenario

For this study, the research team developed two primary long-term electricity demand scenarios for the buildings sector, the first of which was a "maximum energy efficiency" (max-EE) scenario. The max-EE scenario was based largely on recent estimates of long-term technical potential developed by Itron in the 2011 PIER study.

Technical potential reflects the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency were taken.[6] In this sense, technical potential is best interpreted as a theoretical benchmark, particularly over the short-term. For this study, however, the research team wanted to construct an electric load forecast that reflected a policy-driven pathway towards achieving technical potential savings over the long-term, i.e. by 2050. The key policy assumptions reflected in the final max-EE scenario developed for this study are described below.

Policy Assumptions

Over the near-term, the max-EE scenario reflects a regulatory environment similar to that in California today, with utility rebate programs accounting for the vast majority of programmatic activity statewide, and rebates levels assumed to be set very aggressively, i.e. approaching 100% of the incremental cost of each measure. Aggressive utility programs are assumed to dominate California's regulatory environment through 2025, after which statewide programmatic activity is assumed to become more and more dominated by mandatory codes and standards such that by 2050, all end-use equipment replacements would be required to be high-efficiency.

To reflect these policy assumptions, the research team developed near-term measure adoption rates based on the results of the "full market potential" scenario from the 2008 Itron potential

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[6] Applicability limits measure installation to situations where a qualifying end use or technology is present (e.g., water heater blankets for electric water heaters require an electric water heater to be present). Feasibility limits measure installation to situations where installation is physically practical (e.g., available space, noise considerations, and lighting level requirements are considered, among other things).

update study from 2006 through 2025.[7] From 2025 forward, measure adoptions were assumed to be driven by the increasing scope and stringency of codes and standards such that 100% of all installed end-use equipment is high-efficiency by 2050. The key characteristics of the resulting measure adoption rates and electric load forecast are summarized below.

Results

Figures 4-1 and 4-2 show the final energy efficiency "implementation curves" developed for existing residential and commercial buildings by end use. These implementation curves reflect the annual improvement in average end-use UECs from the adoption of energy efficiency measures. Note that Figures 4-1 and 4-2 display these implementation curves in terms of an index that describes the relative rate of progression towards the long-term (i.e. 2050) technical potential for each end use.
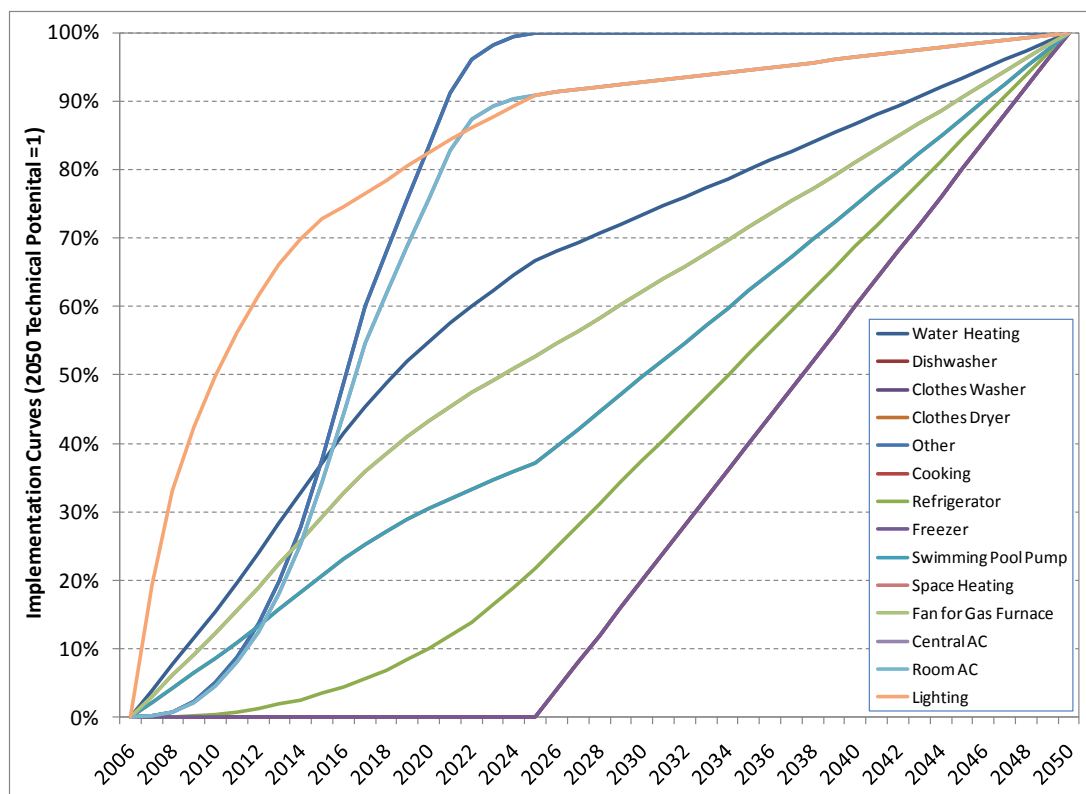
Figure 4-1. *Energy efficiency implementation curves for existing residential buildings.*

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[7] The measure-specific adoption rates for all of the scenarios modeled in the 2008 Itron potential update study are available at:
http://www.calmac.org/startDownload.asp?Name=PGE0264_Final_Report.pdf&Size=5406KB. Note that for this study, the measure-specific adoption rates were aggregated to the end-use level in order to match the level of analysis in the SESAT model. In order to produce meaningful indices of measure adoption at the end-use level, this aggregation was done in terms cumulative energy savings (rather than number of adoptions).

As Figure 4-1 shows, lighting measures are adopted very quickly relative to other types of residential measures under the utility-rebate paradigm, largely due to their cost-effectiveness to customers and the very short useful life and high turnover rate of standard efficiency lighting technologies (i.e. incandescent lamps). In contrast, adoption of longer-lived and more expensive measures such as high-efficiency refrigerators grow at a slower, more linear rate under the utility-rebate paradigm. From 2025 forward, however, measure adoptions for all end uses are assumed to be driven by the increasing scope and stringency of mandatory codes and standards and grow linearly until all 100% of all installed end-use equipment is high-efficiency by 2050.
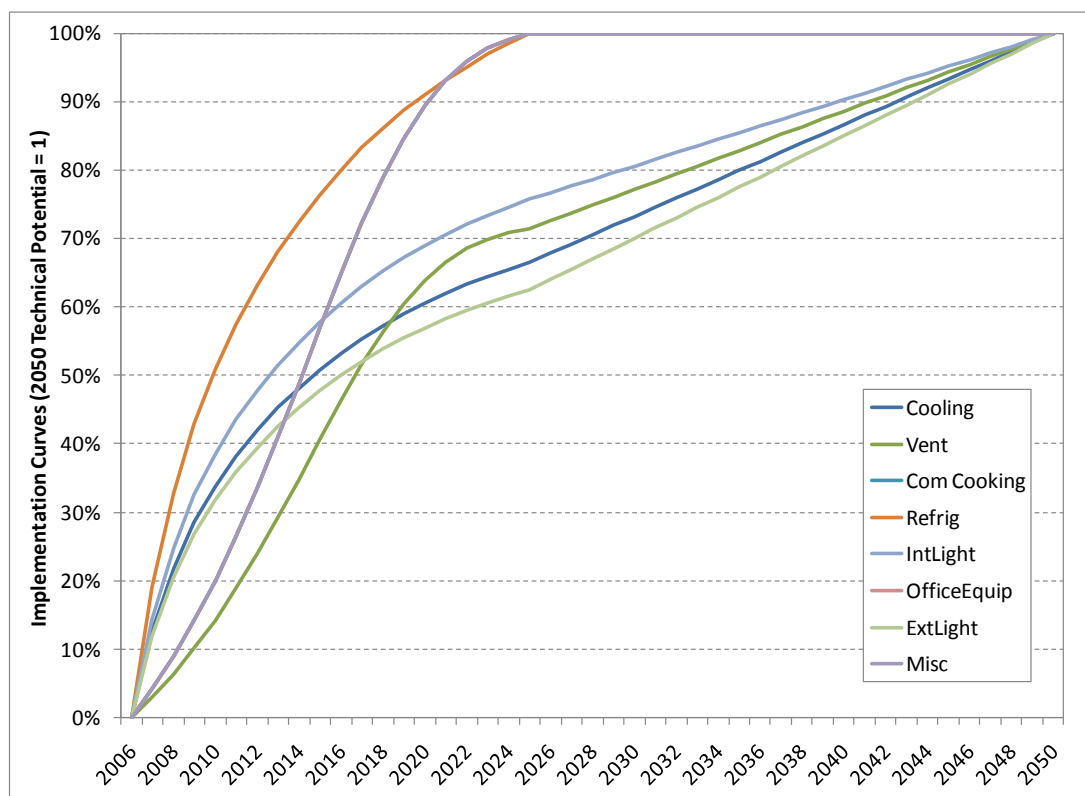
Figure 4-2. *Energy efficiency implementation curves for existing commercial buildings.*

Introducing these energy efficiency implementation curves into the SESAT model produces the total load forecast shown in Figures 4-3 and 4-4. As these figures show, the assumptions in the max-EE scenario yield a zero load growth forecast for the buildings sector, both in terms of annual electric energy consumption (GWh) and in terms of system coincident peak demand (GW). When compared to a long-term load forecast using "frozen efficiency" or baseline UECs throughout the forecast period, the max-EE scenario represents annual energy savings of roughly 1,700 GWh/year and system peak demand savings of roughly 500 MW/year.
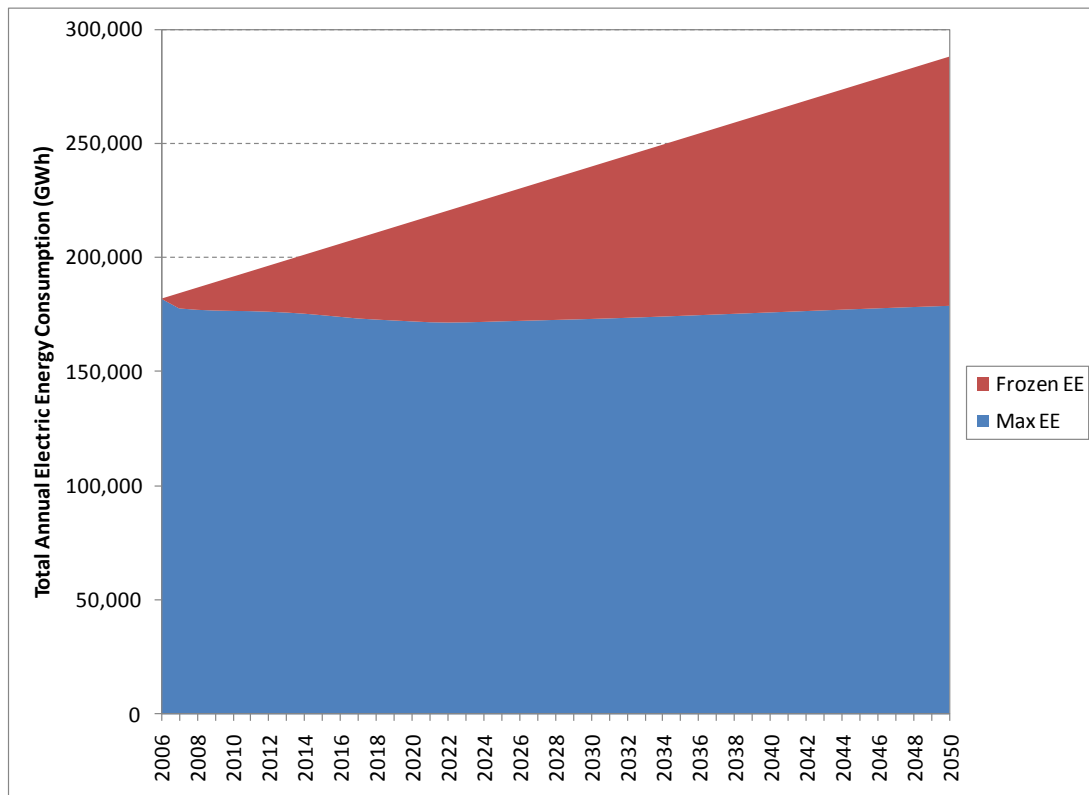
Figure 4-3. *Annual electric energy consumption in buildings in the max-EE scenario for California.*
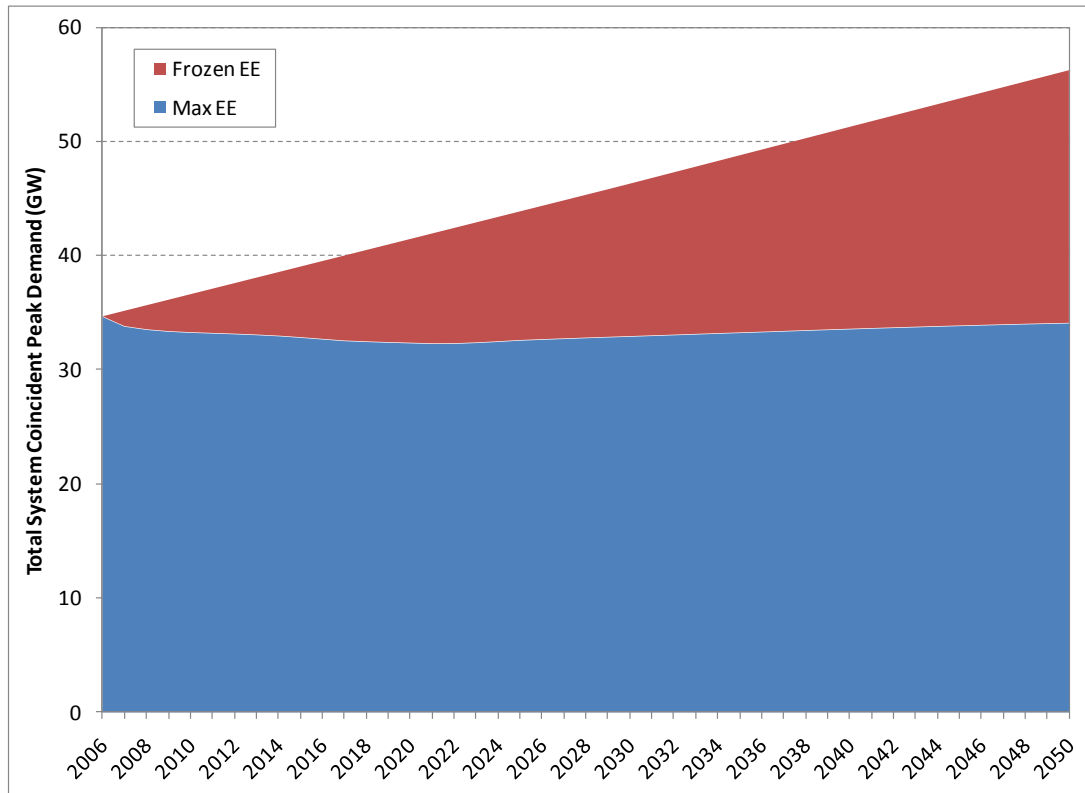
Figure 4-4. *Total system coincident peak demand from buildings in the max-EE scenario for California.*

The zero load growth forecasts shown in Figures 4-3 and 4-4 imply a relatively steady-state world under the max-EE scenario with about 38% overall savings relative to frozen-EE in 2050. However, both the relative and absolute level of technical potential savings vary significantly across measures and end uses in the buildings sector, and therefore the end-use composition of total load changes significantly in the max-EE scenario. Figure 4-5 compares the end-use breakdown of total load in the frozen efficiency forecast versus the max-EE forecast for the residential sector. As the figure shows, lighting accounts for one of the largest shares of total residential electricity consumption in the frozen efficiency case. In the max-EE case, however, lighting accounts for roughly the same share as electric cooking, reflecting the massive reductions in lighting UECs from the adoption of CFLs and LEDs. The decreased importance of lighting loads in turn increases the relative importance of miscellaneous plug loads (labeled as "other" in Figure 4-5) and refrigeration in total residential electricity demand in the max-EE case.
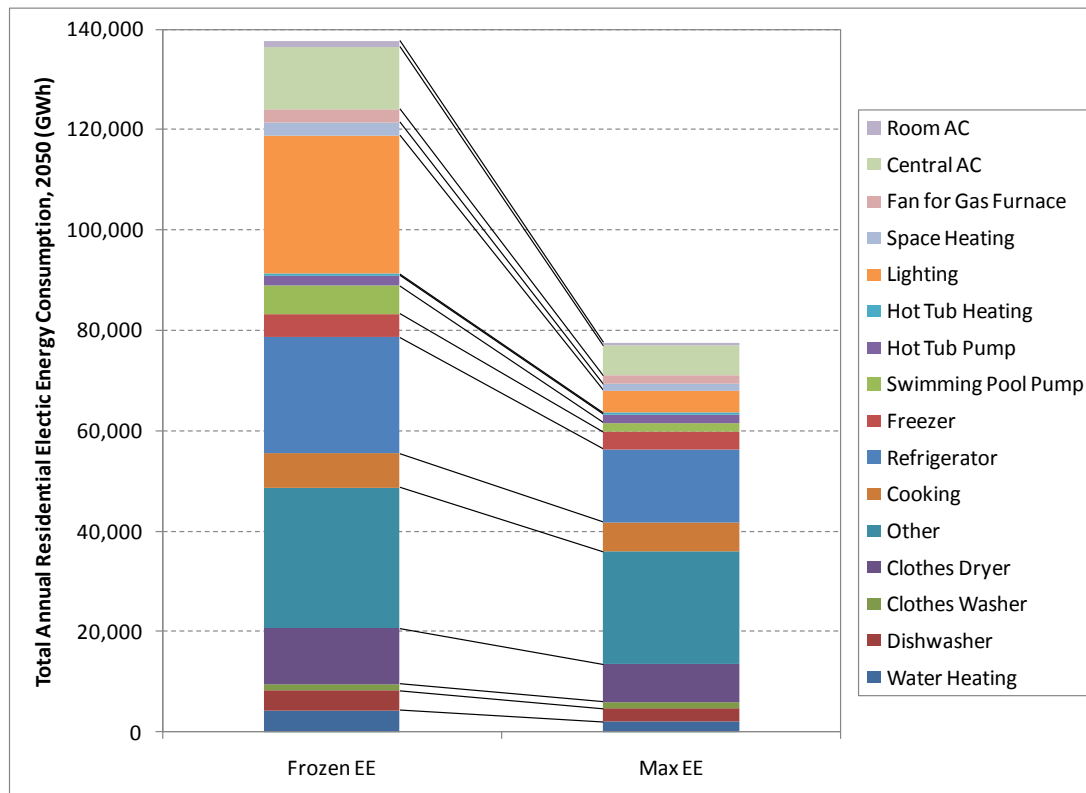
Figure 4-5. *End-use contributions to total load in the residential sector in 2050.*

Figure 4-6 compares the end-use breakdown of total load in the frozen efficiency forecast versus the max-EE forecast for the commercial sector. As in the residential sector, lighting accounts for one of the largest shares of total commercial electricity consumption in the frozen efficiency case but declines in relative importance in the max-EE case due to significant savings from advanced linear fluorescent lighting and control systems. The decreased importance of commercial lighting loads in turn increases the relative importance of office equipment, other miscellaneous plug loads (labeled as "misc" in Figure 4-6), commercial and refrigeration in total commercial electricity demand in the max-EE case.
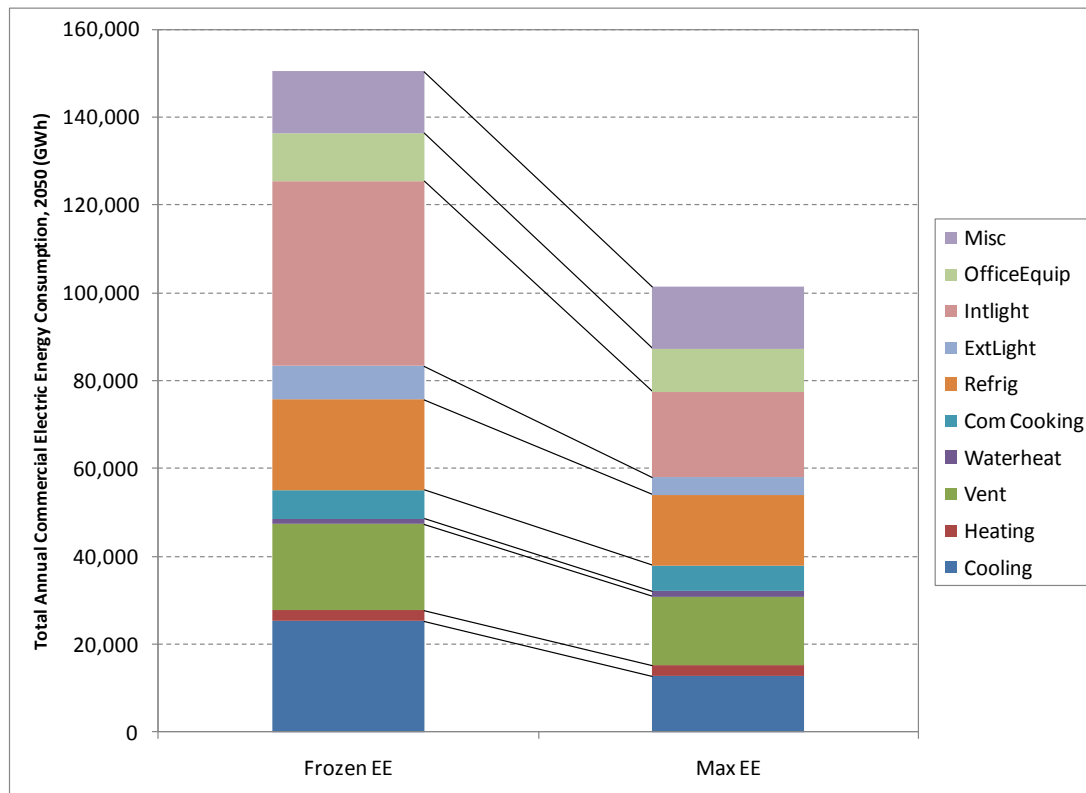
Figure 4-6. *End-use contributions to total load in the commercial sector in 2050.*

Because the distribution of electricity demand (across a day, week, month, and year) varies significantly across the various end uses in buildings, the changes in the end-use composition of total demand in the max-EE case therefore also change the relative temporal distribution of total demand. Figure 4-7 compares the daily system coincident peak demand for each day in the last year (2050) of the frozen-EE forecast and the max-EE forecast. As the figure shows, system peak demand in the max-EE case follows the same general pattern over the course of the year as in the frozen-EE case (albeit at a lower overall level due to overall increases in end-use efficiency) – i.e. a summer peaking system driven by space cooling demand. However, the overall load shape of the max-EE forecast is significantly flatter (particularly in the summer months) than that of the frozen-EE forecast, reflecting the reduced importance of highly dynamic loads from lighting and space cooling the increased importance of relatively flat loads from refrigeration and miscellaneous end uses in aggregate.
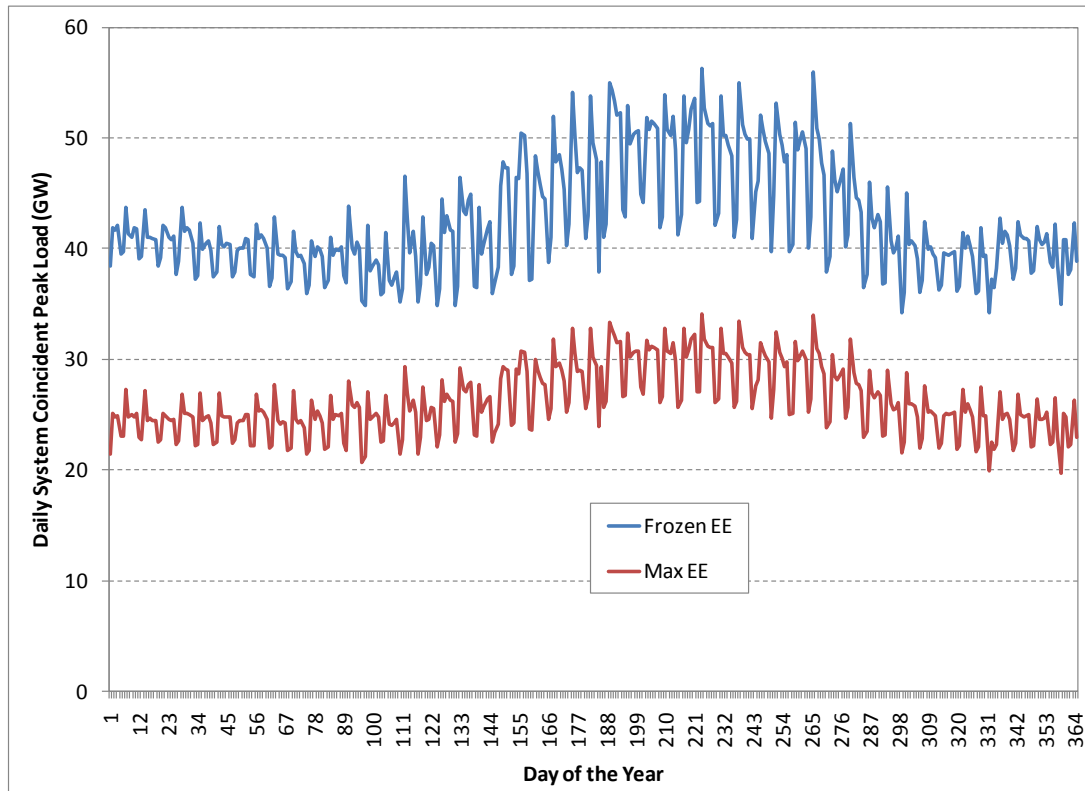
Figure 4-7. *Daily system coincident peak load from buildings in 2050 in California.*

4.6   Maximum Energy Efficiency and Electrification Scenario

The research team also developed a "maximum energy efficiency and electrification" (base case) scenario for this study based on both technical potential for energy savings and fuel-switching away from natural gas towards electricity in the buildings sector. This scenario builds directly upon the max-EE scenario presented above and simply adds assumptions describing a policy-driven shift away from natural gas and towards electricity for particular end uses in the buildings sector.

The key policy assumptions reflected in the final "max-EE + electrification" scenario developed for this study are described below ("max-EE" is equivalent to "technical potential energy efficiency").

Policy Assumptions

Over the near-term, end-use fuel shares are assumed to stay constant at baseline values. However, starting in 2015, codes and standards requiring fuel-switching away from natural gas and towards electricity are assumed to be phased in for key gas technologies and end uses in California in an effort to "electrify" the building sector and maximize the GHG emissions benefits of a de-carbonized electricity supply system.

In order to simulate the load impacts of such a fuel-switching policy, the research team assumed that codes and standards targeting residential and commercial water heating (gas-fired storage water heaters), residential space heating (gas-fired furnaces), and commercial space heating (gas-fired boilers) would be implemented at particular points in time during the forecast period that would mandate all new installations and end-of-life replacements to use electric-powered equivalent technologies.[8] These assumptions were then combined with average useful life estimates for the related gas technologies from the California Database for Energy Efficient Resources to develop annual fuel-switching rates based on stock turnover. The key characteristics of the resulting fuel-switching rates and electric load forecast are summarized below.

Results

Figure 4-8 shows the final fuel-switching rates developed for the water heating and space heating end uses in the "max-EE + electrification" scenario.
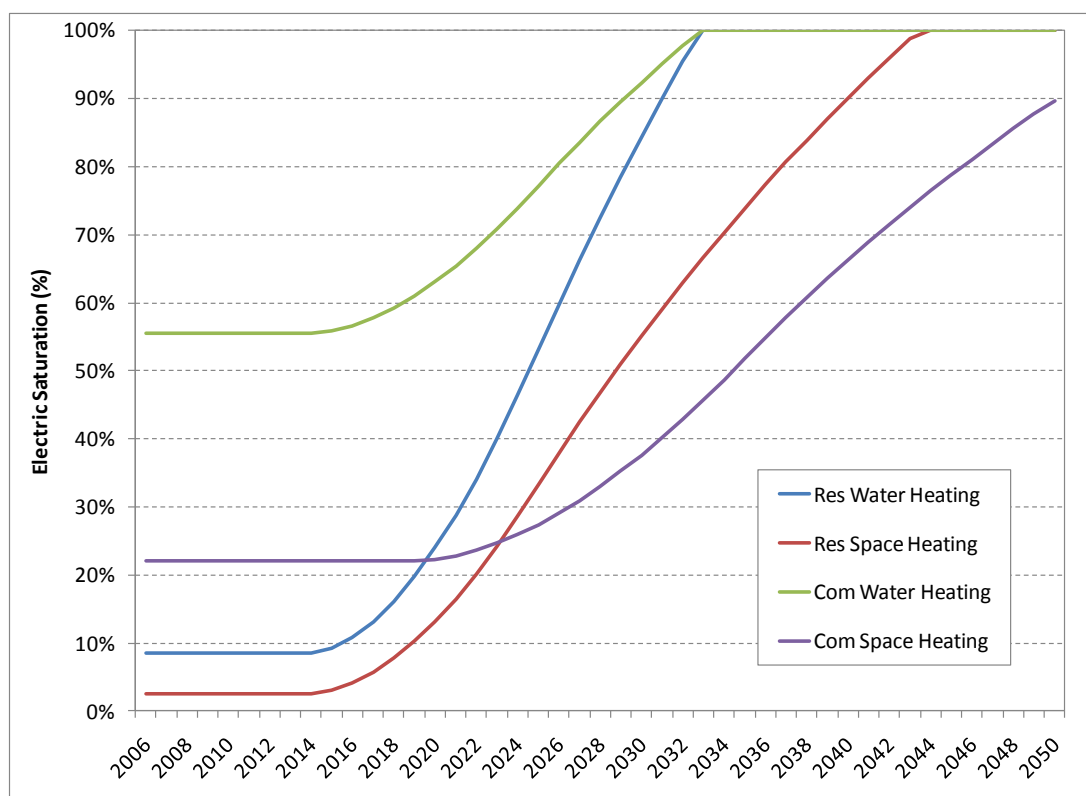
Figure 4-8. *Fuel-switching rates assumed in the max-EE + electrification scenario for California.*

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[8] The specific assumptions used were the following: 1) phase-in of electric storage water heaters (commercial) and heat pump water heaters (residential) starting in 2015, with 100% penetration on the margin by 2025; 2) phase-in of air-source heat pumps starting in 2015, with 100% penetration on the margin by 2025; and 3) phase-in of electric boilers starting in 2020, with 100% penetration on the margin by 2035.

Note that Figure 4-8 shows the fuel-switching rates developed specifically for residential water heating in single family dwellings (SFD), residential space heating for SFDs in climate zone 5 (the SF Bay Area), and commercial water heating and space heating in retail buildings.[9]

As Figure 4-8 shows, the relative level of assumed fuel-switching is largest in the two residential end uses (from 5-10% penetration today to 100% by 2033 and 2044, respectively), whereas the relative level of assumed fuel-switching in the two commercial end uses is significantly more modest due to the significant baseline shares of electricity in commercial water heating and space heating systems.

Introducing these fuel-switching rates into the SESAT model produces the total load forecast shown below in Figures 4-9 and 4-10. As these figures show, complete electrification of water heating and space heating in the building sector over the forecast period has a significant impact on the resulting electric load forecast. In the case of annual electric energy consumption, Figure 4-9 shows that the electrification case produces annual average load growth of 0.4%/year.
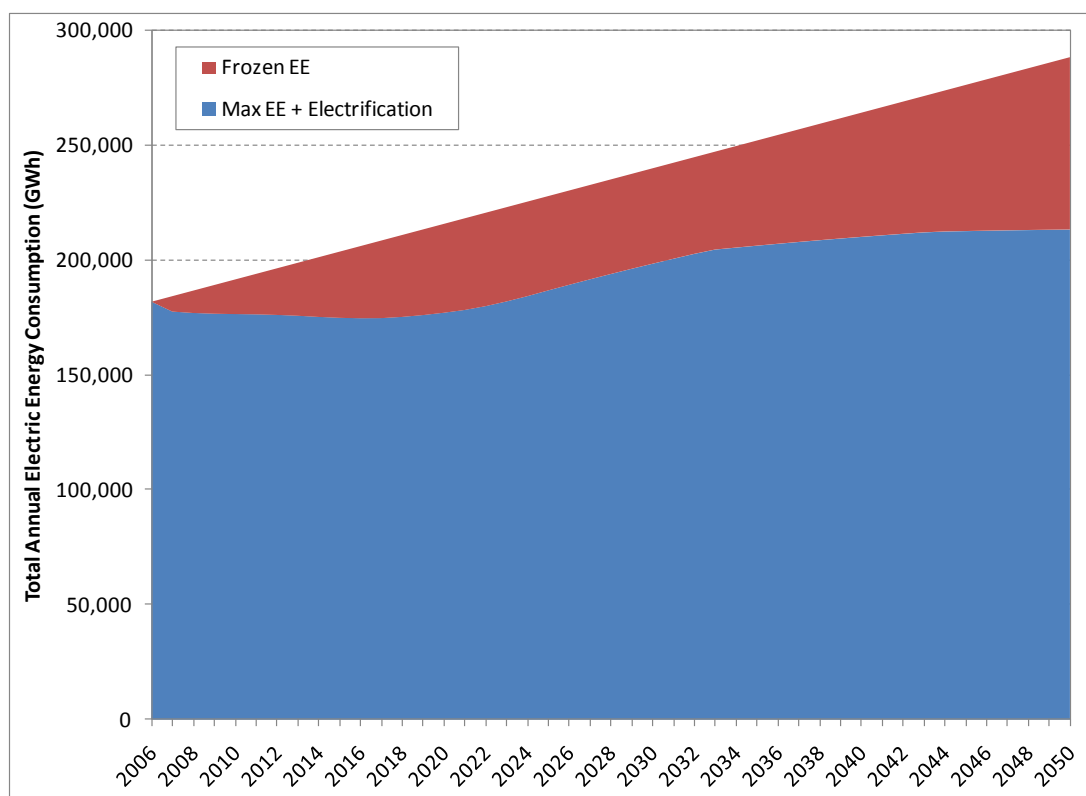
Figure 4-9. *Annual electric energy consumption in buildings in the max-EE + electrification scenario.*

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[9] Fuel-switching rates were developed on a building-type specific basis (for residential and commercial water heating and space heating) and on a climate-zone specific basis (for residential space heating), but, for the sake of simplicity, are not all shown in Figure 4-8.

It should be noted, however, that forecasted load growth in the electrification scenario is not uniform over the forecast period. Indeed, annual electric energy consumption remains flat through 2020 and then grows at 1.1%/year through 2033 and 0.2%/yr for the remainder of the forecast, reflecting the aggressive fuel-switching rates shown previously in Figure 4-8.

From a system peak demand perspective, the impact of the fuel-switching assumptions are even more pronounced, as shown in Figure 4-10 below. Indeed, Figure 4-10 shows that total system peak demand from the buildings sector in the "max-EE + electrification" scenario grows at nearly the same rate overall as in the frozen EE scenario. However, the most of the growth in system peak demand occurs in the latter half of the forecast period, averaging 1.7%/yr from 2025 to 2050.
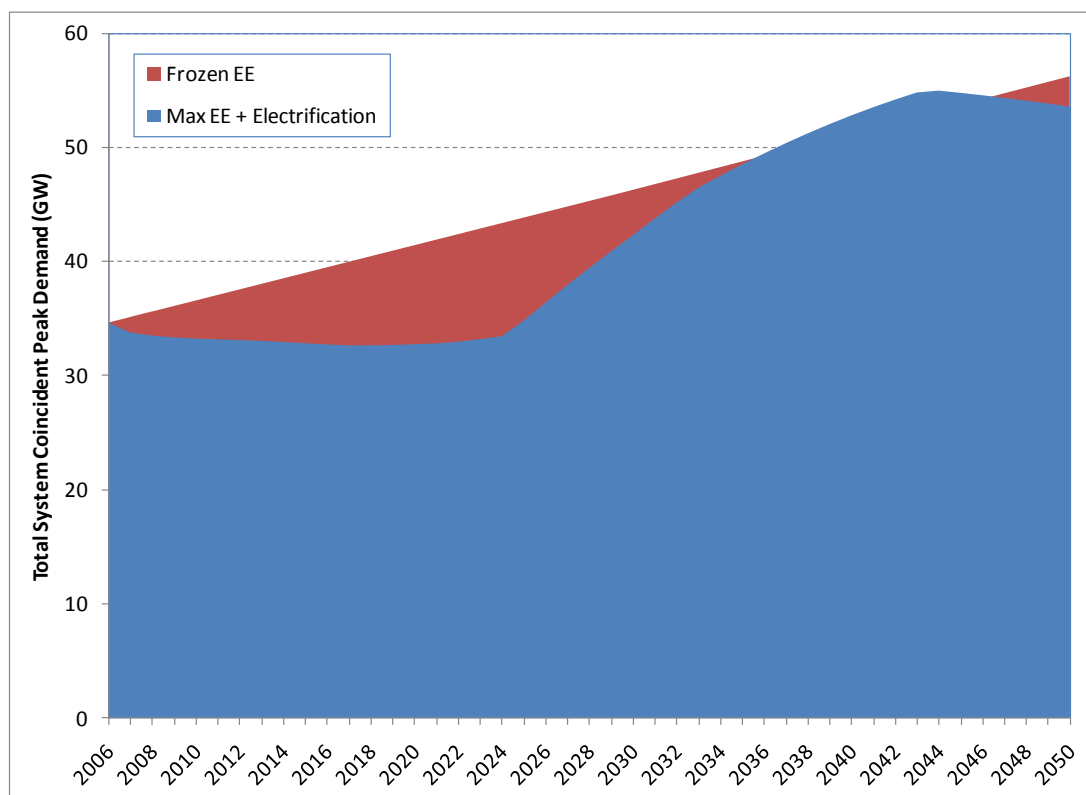
Figure 4-10. *Total system coincident peak demand from buildings in the max-EE scenario + electrification scenario.*

Figures 4-11 and 4-12 show the impact of the assumed fuel-switching rates on the end-use contributions to total forecasted load in the buildings sector. Figure 4-11 shows that electrifying water heating and space heating in the residential sector results in those two end uses accounting for roughly 30% of total residential electricity consumption – a dramatic shift from the max-EE and frozen-EE cases where those two end uses accounted for only 4% and 5% of total residential electricity consumption, respectively.
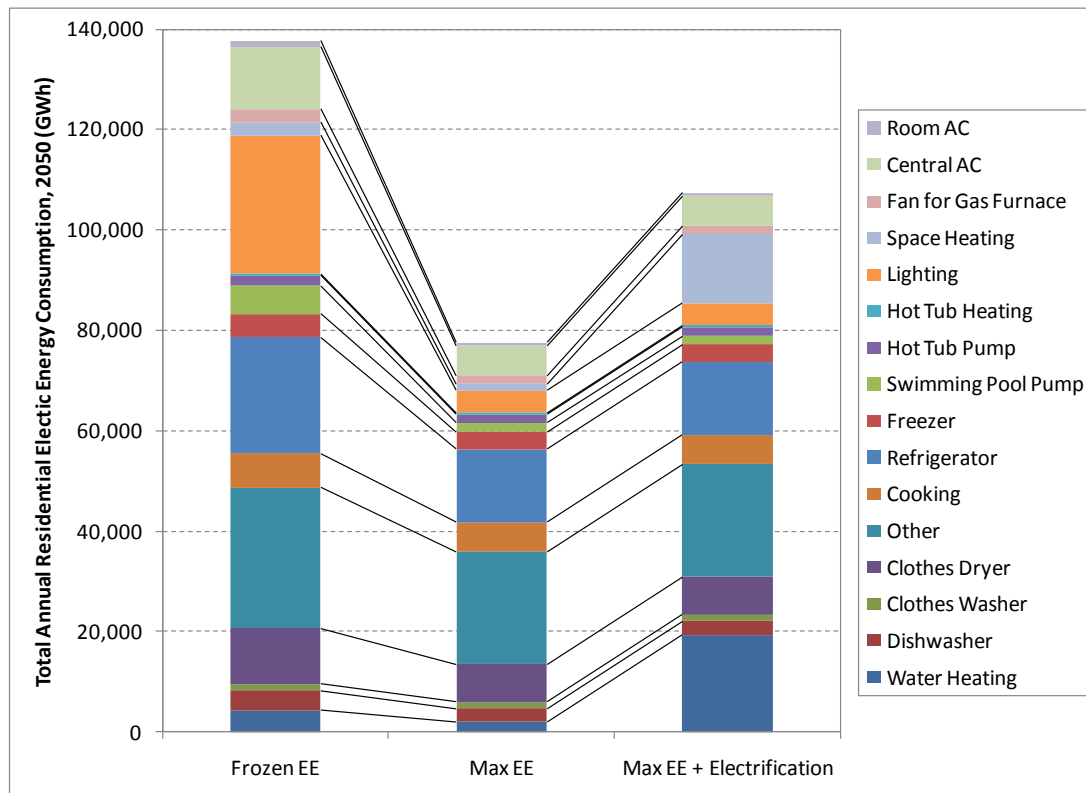
Figure 4-11. *End-use contributions to total load in the residential sector in 2050.*
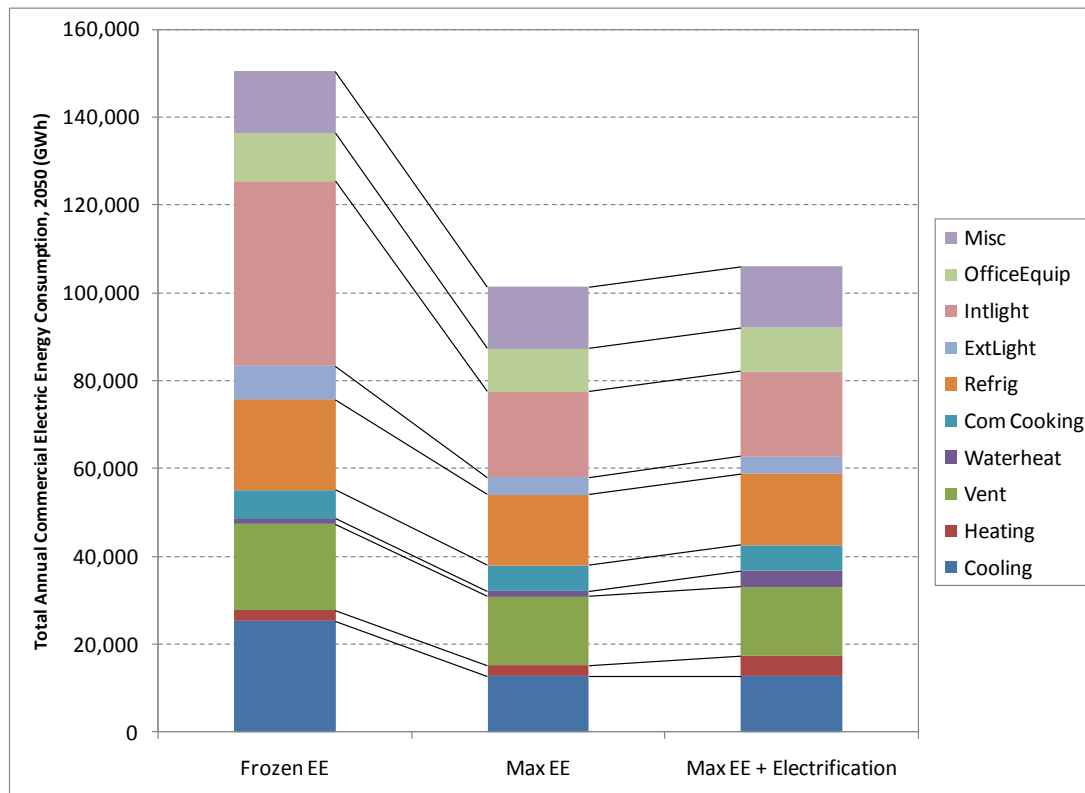
Figure 4-12. *End-use contributions to total load in the commercial sector in 2050.*

In contrast, Figure 4-12 shows that electrifying the heating end uses in commercial buildings results in only slight changes in their relative share of total commercial electricity consumption compared to those in the max-EE and frozen-EE scenarios. This result reflects both the relative insignificance of the heating end uses in commercial buildings and the fairly high baseline penetration of electric space heating and water heating technologies.

Given the dramatic changes in end-use contributions to total residential load shown in Figure 4-11 compared to the insignificant changes to total commercial load shown in Figure 4-12, it follows that the dynamics of total electricity demand from the buildings sector should be begin to follow those in the residential sector. Indeed, as Figure 4-13 shows below, total system coincident peak demand from buildings in the electrification scenario follows a very different pattern over the course the year compared to both the max-EE scenario and the frozen-EE scenario – the system shifts from being summer-peaking and driven by space cooling demand in both residential and commercial buildings to one that is winter-peaking and driven by space heating and water heating demand almost exclusively in residential buildings.
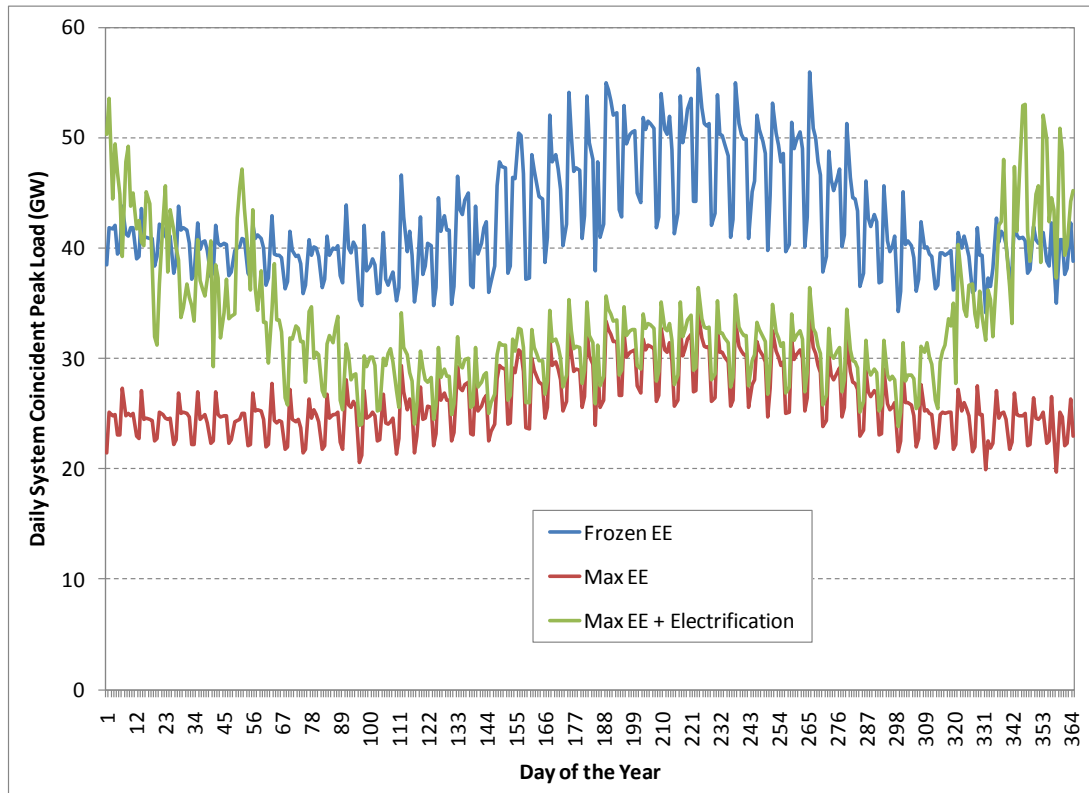
Figure 4-13. *Daily system coincident peak load from buildings in 2050 in California.*

Additionally, the importance of residential space heating and water loads in the electrification scenario also manifests itself in the hourly distribution of total demand during the system peak period. In the max-EE and frozen-EE cases, system peak demand occurs during the mid-afternoon, typically between 2pm and 4pm. As Figure 4-14 shows below, system peak demand in the electrification scenario occurs in the morning prior to the start of business hours and then experiences a secondary peak during the evening hours following the business day. This bi-modal distribution of hourly demand is a direct reflection of the load shapes associated with residential water heating and space heating and their relative importance in total residential electricity demand in the "max-EE + electrification" scenario.
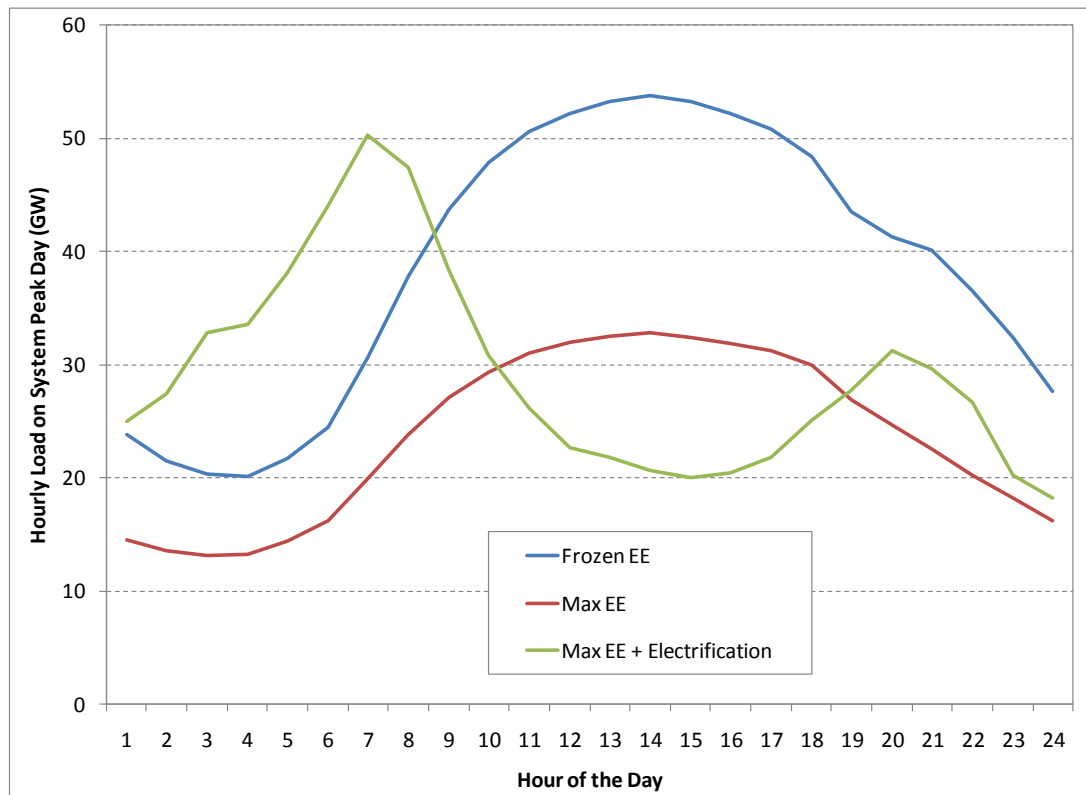
Figure 4-14. *Total hourly demand from buildings on the system peak day in 2050 in California . (Note: system peak day occurs on different calendar days for the three cases).*

5.   TRANSPORTATION DEMANDS AND ENERGY USAGE

Transportation in California is the largest contributor to energy use and greenhouse gas emissions and as such faces an important challenge to make significant and deep reductions in GHGs if California is to meet its long-term emissions reduction goals.

A number of studies have assessed the potential for reducing GHG emissions in transportation and this analysis draws on this literature to develop a scenario for the transport sector in California. Much of the previous analysis of efficiency and emissions reduction potential focuses on light-duty vehicles (LDVs) as it is the largest fuel-using and emissions-producing subsector within transportation.

Transportation emissions can be decomposed into the product of four terms based upon a Kaya-type formulation (Kaya, 1990 and Yang 2009).

$$CO_{2,Transport} \equiv (Population)\left(\frac{Transport}{Person}\right)\left(\frac{Energy}{Transport}\right)\left(\frac{Carbon}{Energy}\right) \qquad (1)$$

$$CO_{2,Transport} \equiv \quad P \quad \times \quad T \quad \times \quad E \quad \times \quad C \qquad (2)$$

Transport intensity (T) is defined as individual passenger, vehicle or freight miles per capita (e.g., miles/person), depending on the particular subsector. A key challenge for meeting the 80% emissions reduction goal in 2050 is that these terms (P and T) are projected to increase by 2050. The latter two parameters in the identity are energy intensity (E), which describes the energy use per-mile (e.g., MJ/mile) of transport, and carbon intensity (C), which describes the carbon emissions per unit of fuel energy (e.g., gCO_2e/MJ).

This framework highlights the fact that emissions reductions from transportation can be the result of reducing any of these terms, although the latter three are most often discussed. Most efforts to reduce emissions will focus on reducing travel demand, reducing vehicle energy use or switching to cleaner types of fuels.

5.1   In-State versus Overall Emissions

State-level emissions for transportation can fall into one of two categories; emissions from trips that fall entirely within state boundaries (i.e. *In-state*) and from trips that cross state boundaries (i.e. *Out of state*). In general, only *In-state* transportation emissions are regulated by the state. However, it is important to keep an inventory and understand the contribution to emissions from *Out of state* sources as well. In some subsectors, the *Out of state* category can be further broken down into *Interstate* and *International* trips and emissions.

5.2   Light-duty vehicles

Light-duty vehicles are the passenger cars and light trucks that make up the vast majority of vehicles found on highways. There are over 25 million light-duty cars and trucks in California.

Nearly all of them, in California as elsewhere in the U.S., are powered by gasoline internal combustion (spark-ignited) engines. Light-duty vehicles make up roughly 67% of total *in-state* transportation emissions (and about half of total transportation emissions). There are a number of alternative technologies for LDVs commercially available currently or will be over the next few years, but none of these alternatives has achieved a significant penetration into the market. There are many classes of cars and trucks ranging from sub-compact cars all the way to large trucks, vans and SUVs.

5.2.1 Approach

This analysis uses a light-duty stock turnover model to represent the adoption and fleet persistence of vehicles in the system. This model is based upon previous light-duty analysis for California (CEC 2008). This analysis combines all vehicle classes into one average class and tracks the adoption and stock of four key vehicle types based upon drivetrain (conventional ICE vehicle, hybrid electric vehicle (HEV), plug-in hybrid electric vehicle (PHEV) and full battery electric vehicle (BEV)). Vehicle efficiency, mileage, stock and vintage of each vehicle type were tracked each year to calculate total fuel demanded by type (gasoline or similar liquid fuel and electricity). Hydrogen fuel cell vehicles were not considered in this analysis.

5.2.2 Vehicle efficiency

The fleet of light-duty vehicles currently operating in California is relatively inefficient. There is significant potential for improvements in fuel economy even without changes to the drivetrain. However, the use of an electric drivetrain, including hybridization, plug-in hybrids and full battery vehicles can further increase the efficiency of vehicles. Electricity is a higher quality fuel than gasoline and can be converted to mechanical work with much greater efficiency on a vehicle than a liquid fuel in an engine.

Conventional gasoline powered vehicles can improve efficiency quite a bit over the next few decades by adopting a number of near-term technologies, including variable valve timing, direct injection, cylinder deactivation, better transmissions (continuously variable transmission), vehicle weight reduction, improved aerodynamics. These factors, if all applied to improving fuel economy, would lead to a doubling of fuel economy of conventional vehicles by 2050 (Kromer 2007, NRC 2011) to around 42 mpg[10].

Hybridization increases efficiency by integrating an electric motor and storage batteries with the conventional engine, allowing for smaller and more efficient engine operation, as well as energy capture through regenerative braking. It is assumed that hybrids may achieve up to 64 mpg by 2050. A plug-in hybrid electric vehicle (PHEV) is similar to a hybrid except that the battery is larger than in a hybrid and can be charged via plugging into the electricity grid. The efficient operation of an electric drivetrain enables significantly higher energy efficiency when operating on electricity (charge depleting mode), though when the battery is depleted (i.e. operating in charge sustaining mode), a PHEV will operate with similar fuel economy to a hybrid. The size of the battery will

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[10] Fuel economy numbers quoted in the text are on-road numbers, which will be lower than tested fuel economy numbers, such as from the EPA.

determine the relative fraction of driving that is powered by gasoline vs electricity. Over time, it is assumed that the battery capacity of the PHEV fleet increases and thus the fraction of miles driven on electricity increases from 25% in 2010 to 60% in 2050 (which corresponds to about a 12 mile all-electric battery range in 2010 increasing to a 40 mile range in 2050). This corresponds to a combined fuel economy (on gasoline and electricity) of approximately 91 mpgge[11]. BEVs always use electricity to operate and are quite efficient, achieving 126 mpgge (0.26 kWh/mile) for new vehicles in 2050. The fuel economy values quoted are for new vehicles, but the fleet average fuel economy is lower due to persistence of older vehicles in the fleet (approximately 6% of the fleet in any given year are new vehicles).

Not considered here is aggressive material substitution such as lightweight carbon fibers for vehicle light weighting, nor "out of paradigm" vehicle design concepts. These would provide further technical potential efficiency savings but would face adoption and insertion issues in the auto industry and marketplace, although there appears to be more interest in these area from automakers.[12]

5.2.3   Travel demand and vehicle adoption – Base Case and High Electrification Cases

Base Case

In 2010, conventional gasoline vehicles make up the vast majority of the vehicle fleet (~99%). Vehicle sales adoption curves assume for the base case is shown in Figure 5-1. This figure shows the projected annual sales mix by vehicle drivetrain to 2050. Hybrids grow quickly and, by 2050, become the largest component of the vehicle fleet (36%), with PHEVs and BEVs at 33% and 23% respectively (Figure 5-2). Given the mix of vehicle types, including a range of older and newer vehicles of each type in the fleet, the fleet average fuel economy is about 72 mpgge.

High Electrification Case

In this case, a much more aggressive transition to PHEVs and hybrids are assumed with conventional gasoline vehicles phasing out by 2024, and battery electric vehicles ramping to 50% by 2050. In 2050 the passenger fleet is dominated by PHEV and BEV at 57% and 37% respectively. Fleet average fuel economy in 2050 is about 91 mpgge (Figures 5-4 to 5-6). A transition to electric powered vehicles at this rate would be difficult to implement in practice. Beyond electric vehicle cost and availability issues, lack of widespread electric charging infrastructure could limit market penetration. However this case is a useful limiting case for modeling fuel reduction and electricity system requirements in world where conventional vehicles are essentially eliminated by 2050. The degree of electrification in other vehicle sectors (truck, rail, bus) is the same for both the base and high electrification scenarios.

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[11] Miles per gallon of gasoline equivalent – the number of miles that a vehicle can travel using the amount of energy in a gallon of gasoline (120 MJ = 33.3 kWh)

[12] See for example http://www.autospies.com/news/BMW-Fights-Volkswagen-for-Carbon-Fiber-Supremacy-64055/; also http://www.oilendgame.com/ accessed on August 3, 2011; also see Lovins 2004.
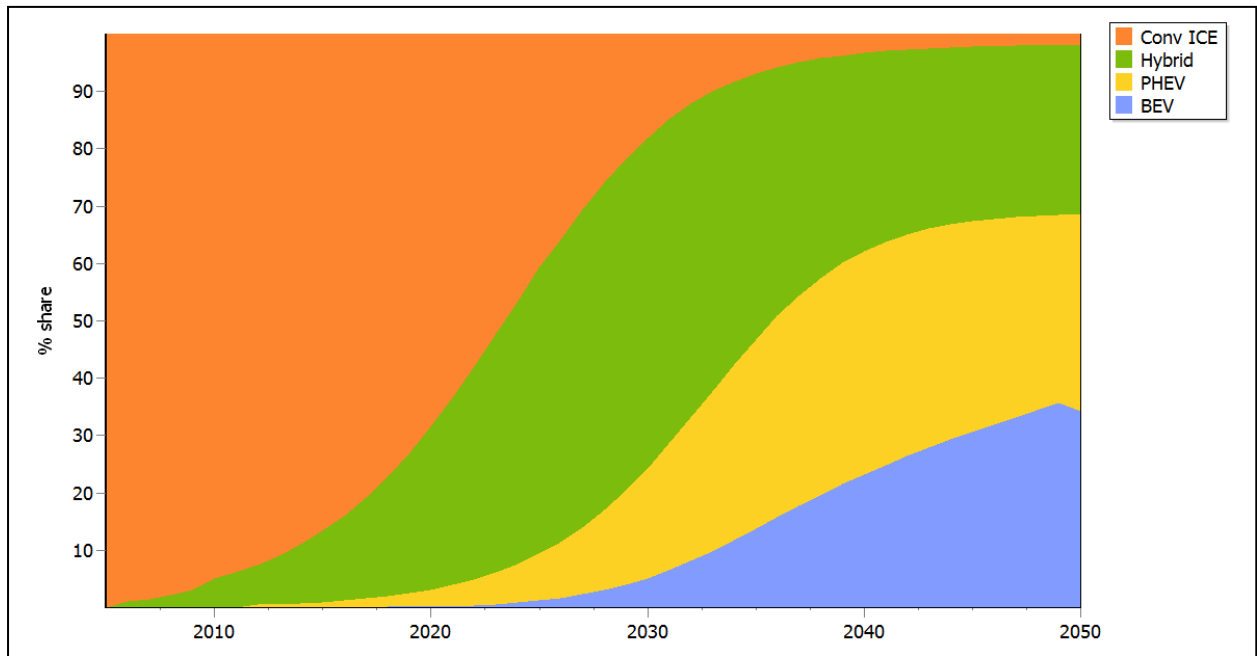
Figure 5-1. *Vehicle sales adoption curves assumed for vehicle electrification base case.*
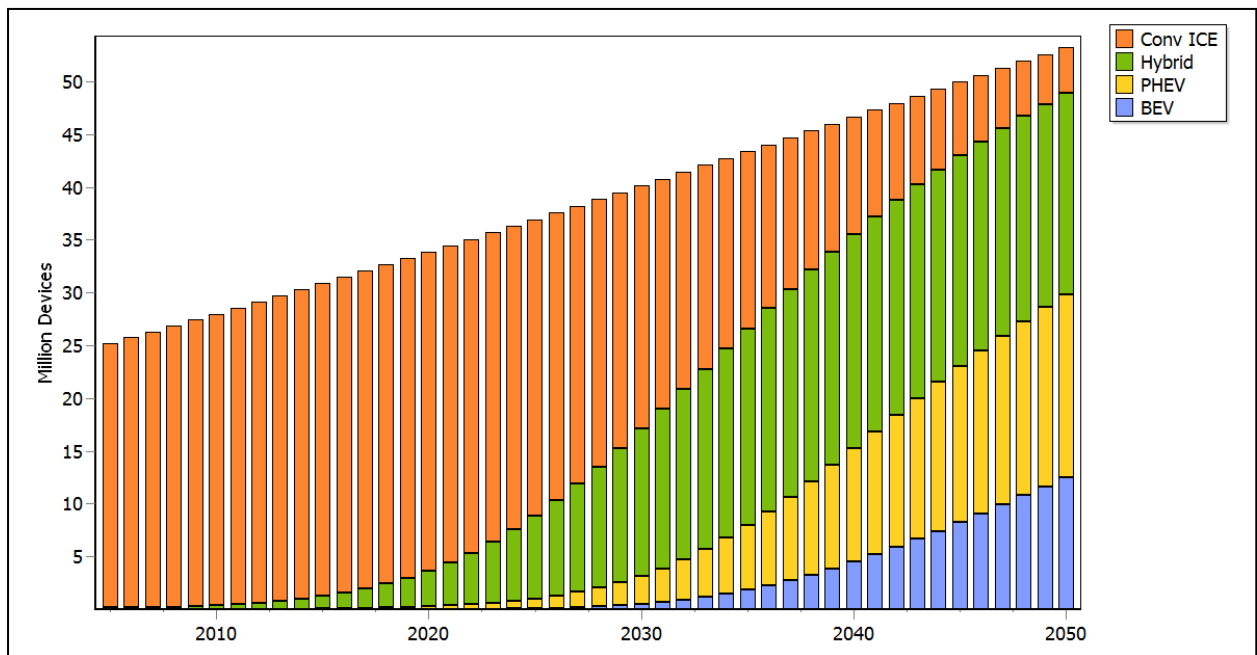
Figure 5-2. *Total number of light-duty vehicles by type in base case.*
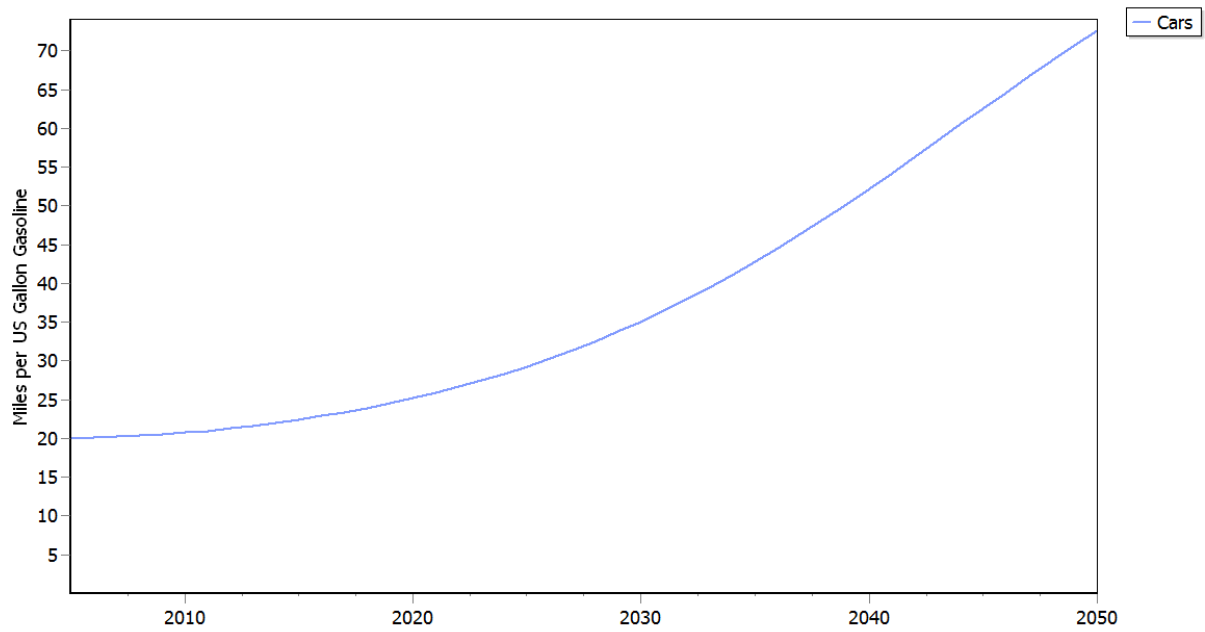
Figure 5-3. *Fleet average fuel economy for base case.*
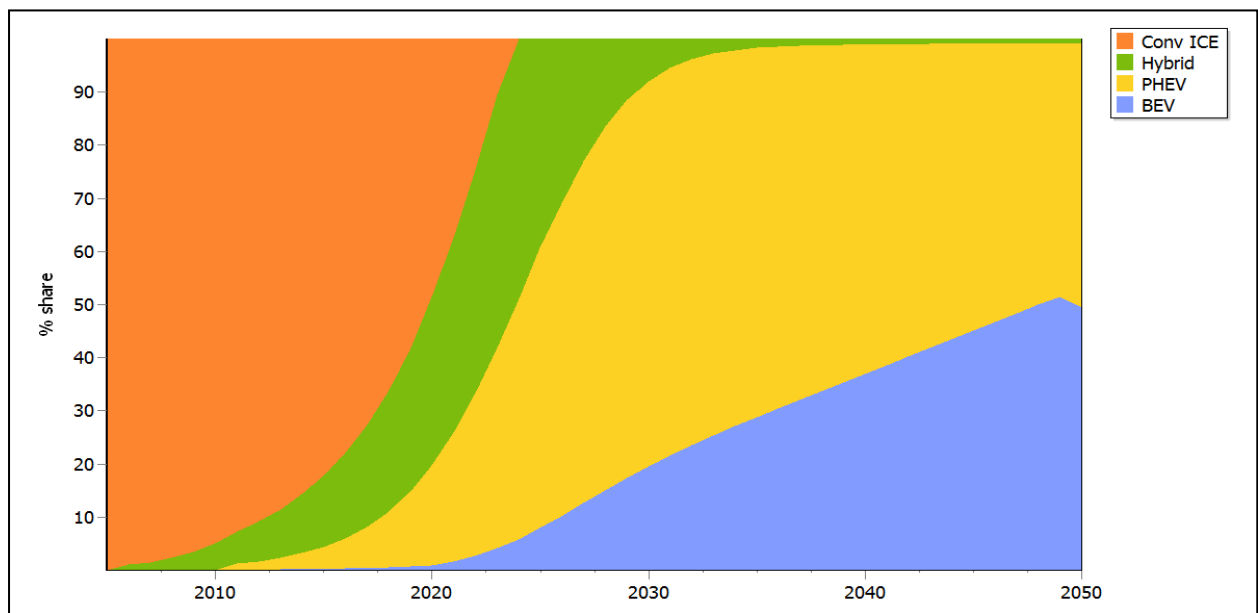
Figure 5-4. *Vehicle sales adoption curves assumed for high electrification case.*
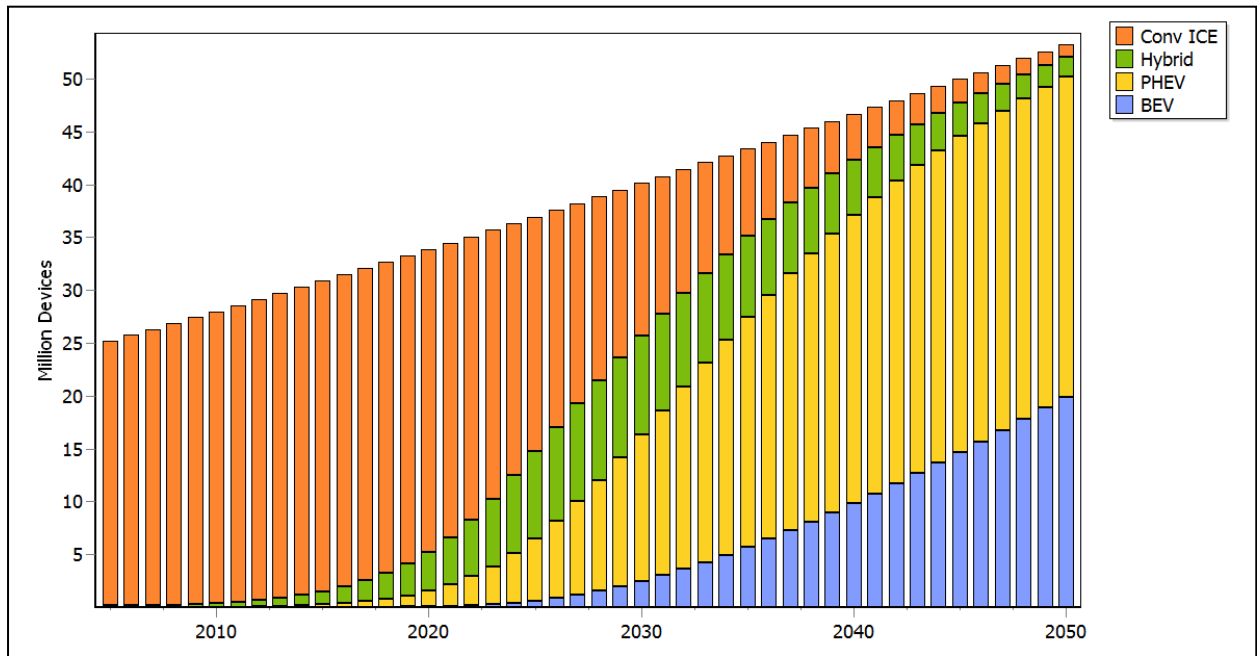
Figure 5-5. *Total number of light-duty vehicles by type in high electrification case.*
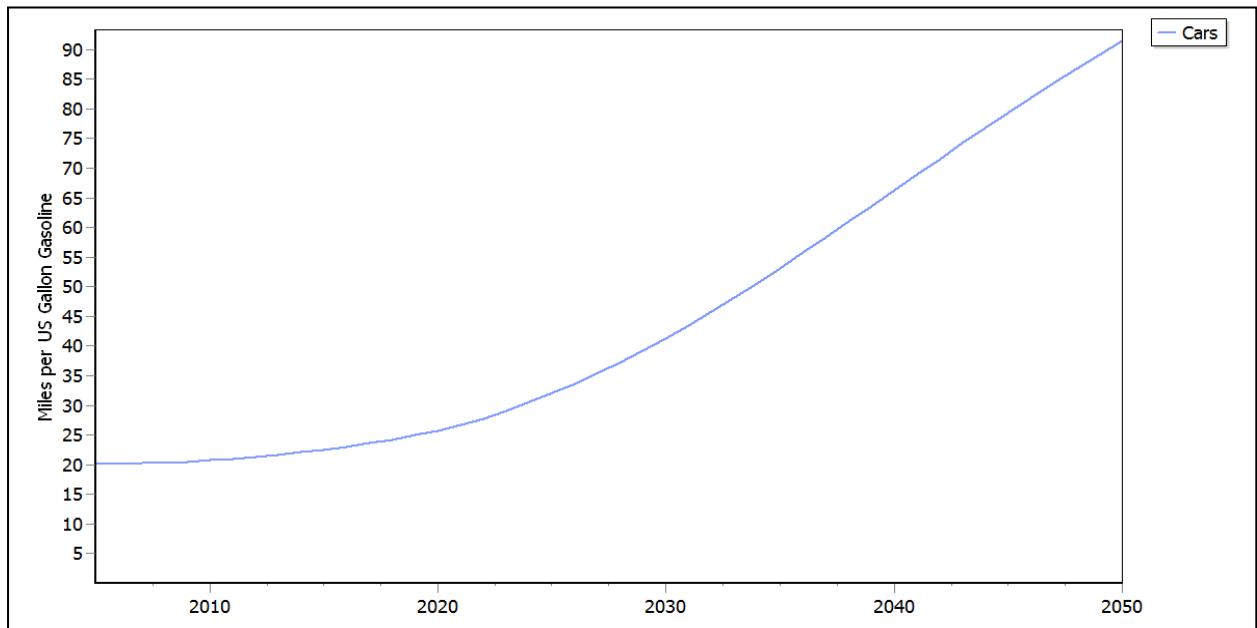
Figure 5-6. *Fleet average fuel economy for high electrification case.*

5.2.4 Fuel Use

Base Case

Annual VMT for new vehicles is assumed in this analysis to remain relatively constant from 2010 until 2050, but due to population growth, the total VMT for the state increases.   In the base case scenario we further assume that vehicle ownership per capita increases from current 0.7 to 0.9 vehicles per capita, consistent with U.S. trends (DOT 2011). In this scenario, total VMT increases to 615 billion miles in 2050

Total fuel usage declines significantly (47% from 2010 to 2050) as shown in Figure 5-7.   This is due primarily to the large increase in light-duty fleet fuel economy (240% increase). From an energy security perspective the amount of liquid fuels used (potentially coming from petroleum) declines even more substantially (65% reduction).   Electricity demand increases to 85,000 GWh in 2050, split about evenly between PHEVs and BEVs.   Overall electricity powers about 45% of vehicle miles in 2050 (Figure 5-10).

High Electrification Case

In this scenario, total VMT increases to 615 billion miles in 2050 as in the base case and total fuel usage declines significantly (56% from 2010 to 2050) as shown in Figure 5-11. From an energy security perspective the amount of liquid fuels used (potentially coming from petroleum) declines even more substantially (83% reduction).   Electricity demand increases to 138,000 GWh in 2050, again split about evenly between PHEVs and BEVs. Overall electricity powers about 72% of vehicle miles in 2050 (Figure 5-14).
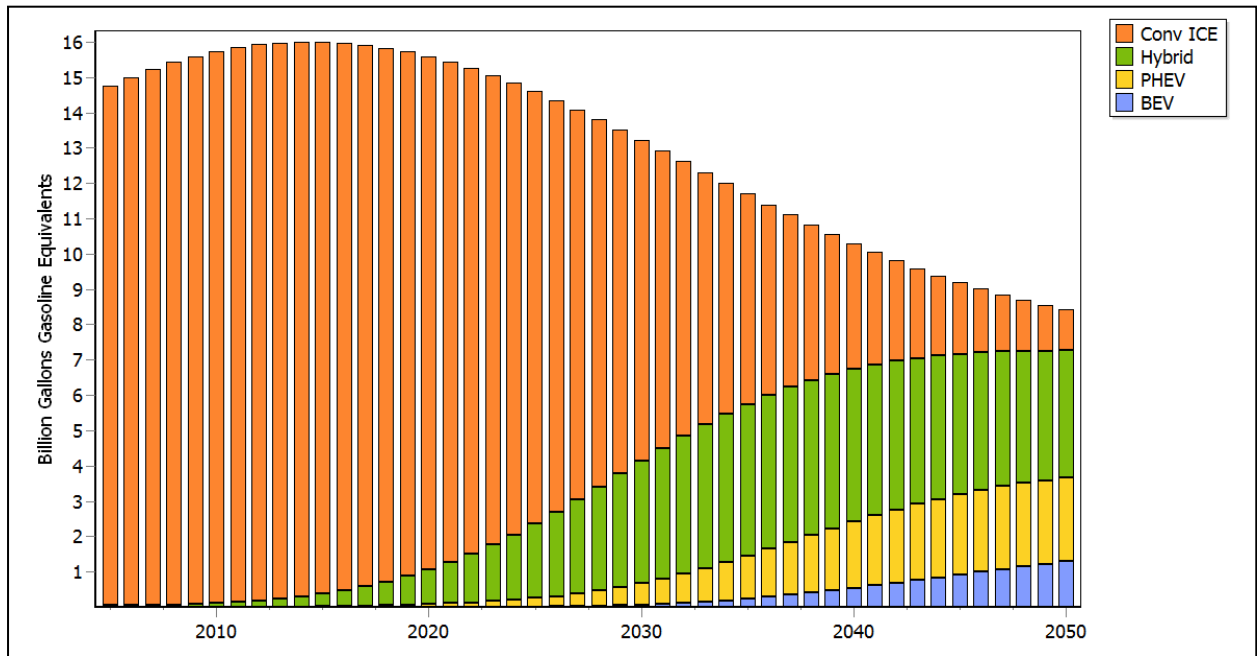
Figure 5-7. *Fuel use by type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles for base case. Here end use electricity demand is included but in units of Bgge.*
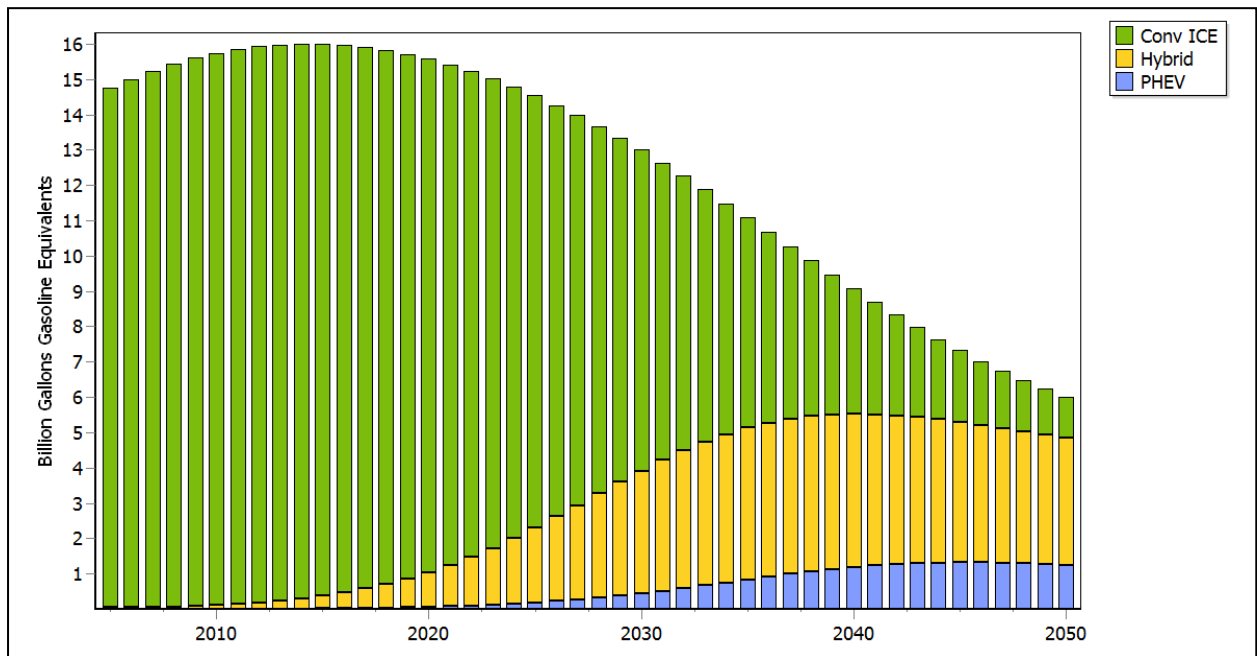
Figure 5-8. *Base case liquid fuel use by vehicle type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*

46
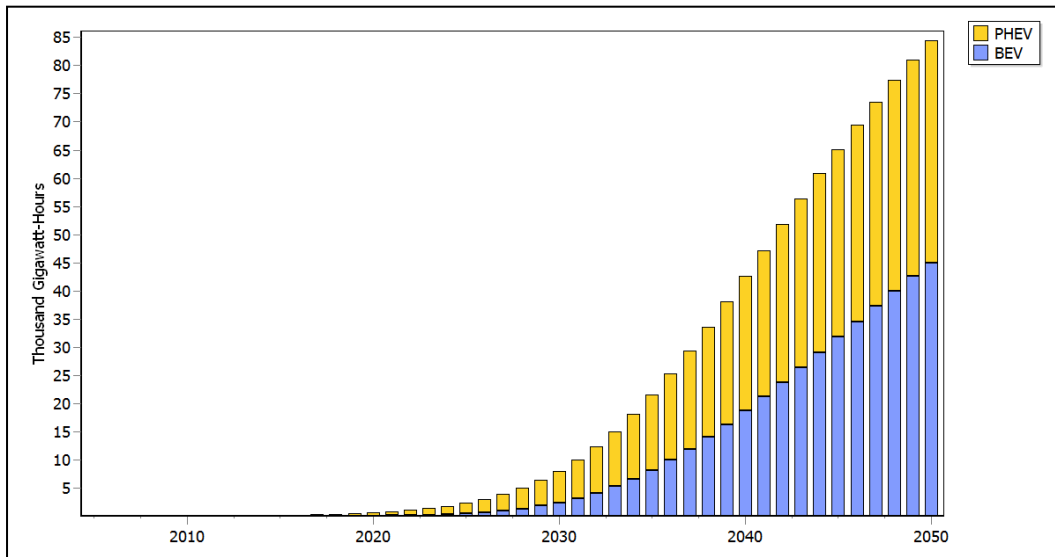
Figure 5-9. *Base case electricity demand for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*
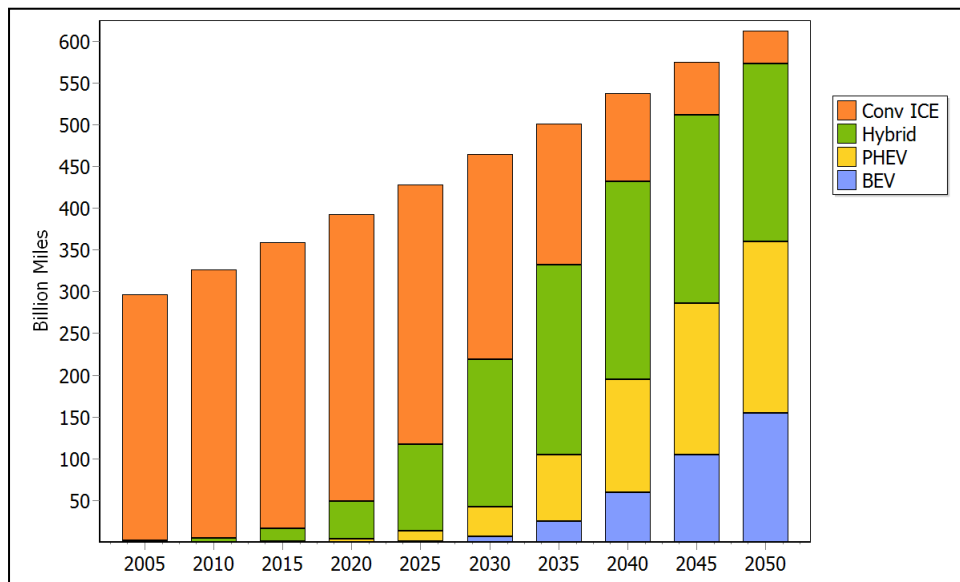
Figure 5-10. *Vehicle electrification LDV mix 2050 . Electricity powers about 45% of vehicle miles in 2050 (BEV plus about half of PHEV miles)*
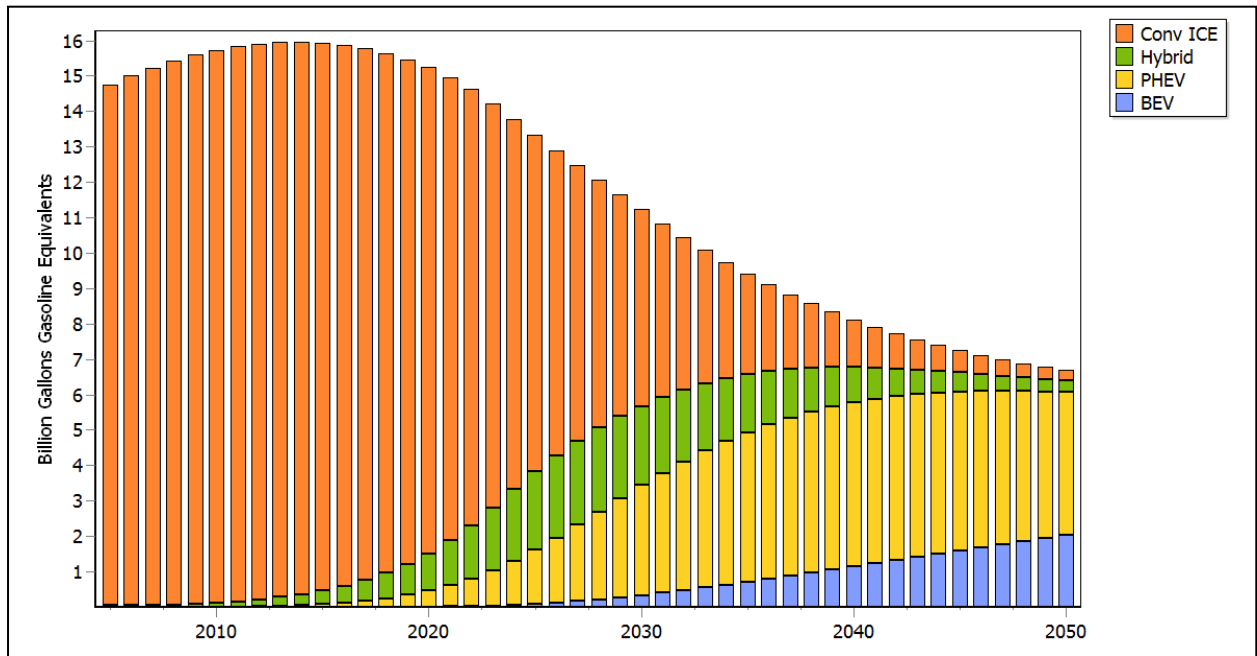
Figure 5-11. *Fuel use by type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles for high electrification case. Here end use electricity demand is included but in units of Bgge.*
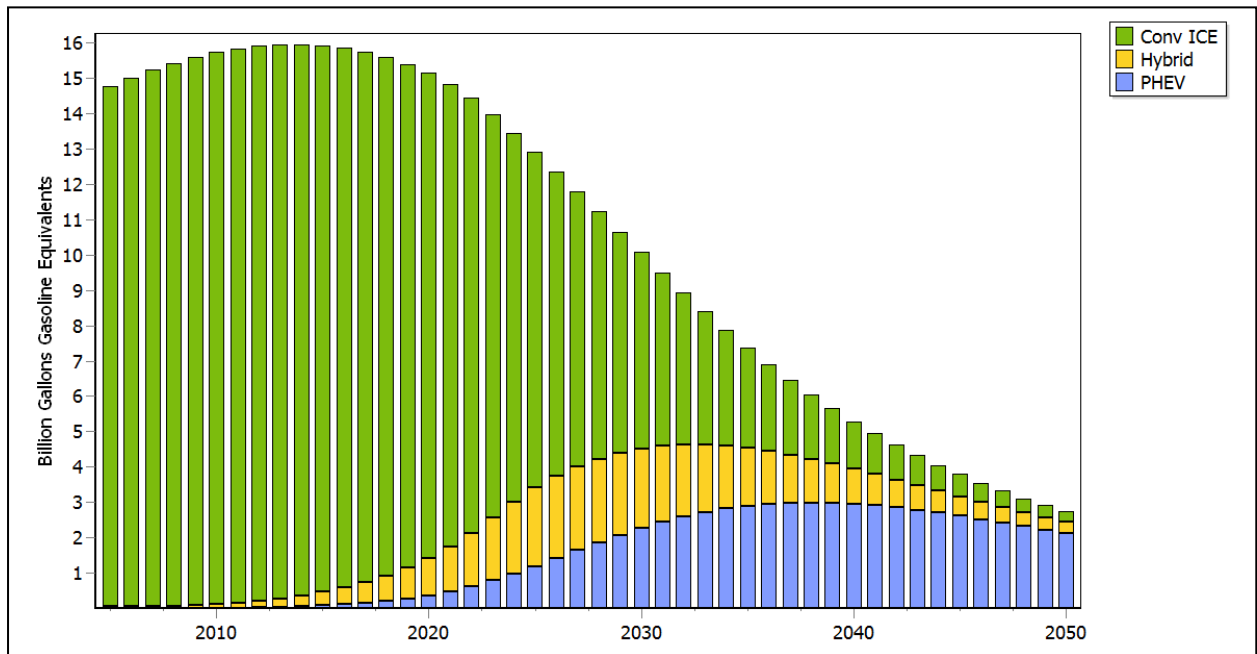
Figure 5-12. *High electrification case liquid fuel use by vehicle type for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*
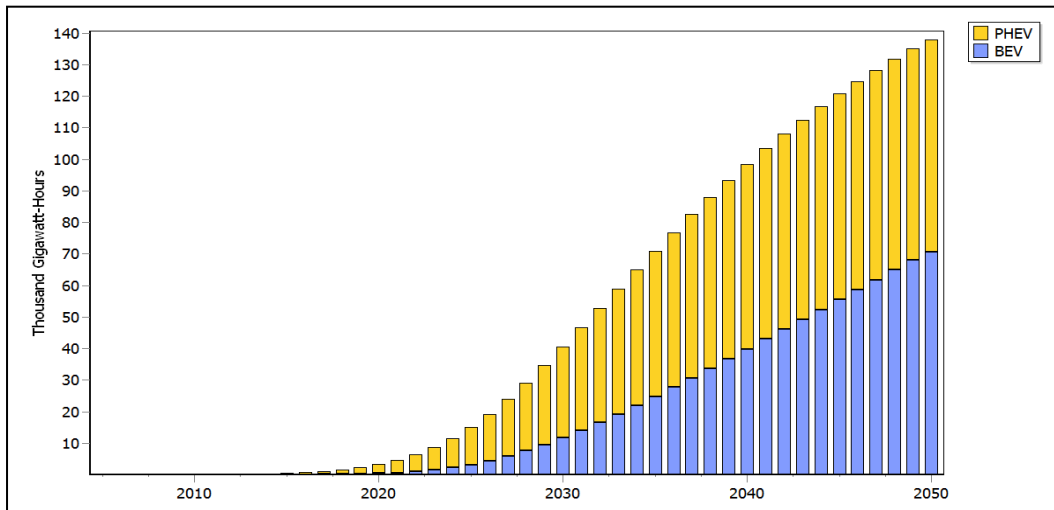
Figure 5-13. *High electrification case electricity demand for light-duty vehicles with increasing vehicle ownership per capita and flat vehicle miles travelled for new vehicles.*
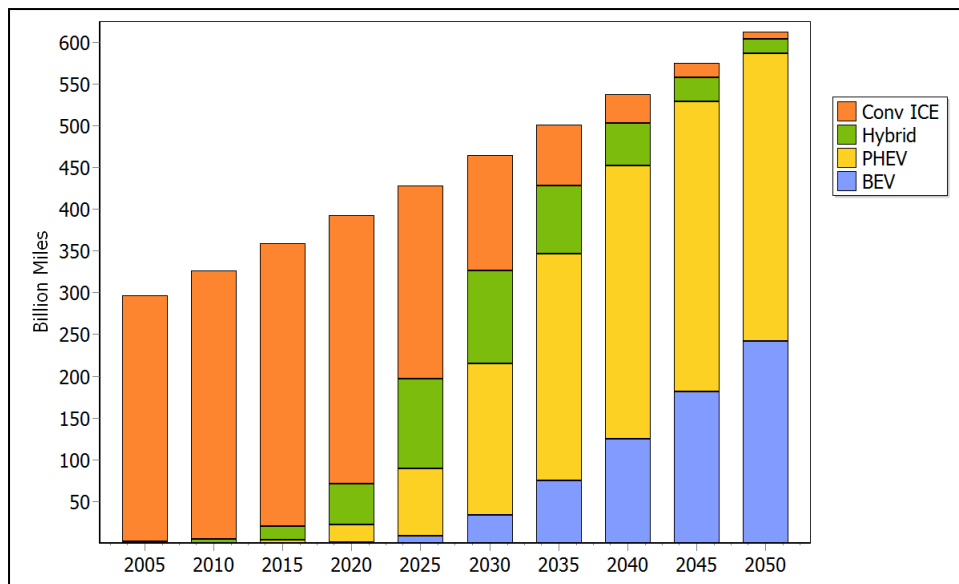
Figure 5-14. *Vehicle electrification mix in high electrification case. Electricity powers about 72% of vehicle miles in 2050 (BEV plus about half of PHEV miles).*

5.3 Medium and heavy duty trucks

Medium and heavy-duty vehicles mostly consist of large trucks with diesel engines that are designed to carry goods and freight and can come in a variety of sizes (up to 75 feet long and 100 tons). These vehicles and their engines receive a great deal of wear because they are driven several hundred thousand miles in their lifetime, carrying large and heavy loads. Consequently, durability, efficiency, and fuel costs are important considerations. These trucks have primarily used efficient

49

diesel engines for energy conversion, because of their efficiency, durability and high power output. The challenge for lowering emissions from the medium and heavy duty truck sector is that alternative fuels and drive trains may not be acceptable for the demanding applications that use these vehicles.

One of the major barriers for the use of electricity and hydrogen as alternative fuels is in energy storage. The energy density of electricity storage in batteries or hydrogen in compressed gas tanks (as are being discussed for light-duty EVs and FCVs) are much lower than diesel fuel on a gravimetric and volumetric basis (See Figure 5-15). This energy storage challenge would negatively impact the vehicle cargo capacity and range. Long-haul trucks typically have fuel capacity over 200 gallons of fuel and get between 5-7 miles per gallon. This means that they typically can drive over 1000 miles between refuelings (Lutsey 2009).

Storing enough energy in the form of batteries or compressed hydrogen to get an adequate range would significantly impinge on the cargo space, reducing the potential value of cargo as well as add significant weight to the vehicle, hurting fuel economy. Also critical is the issue of power density for fuel cells and batteries relative to diesel engines. Diesel engines are quite efficient with peak efficiencies around 45% though average efficiency over a drive cycle would be lower (<40%). Thus, they would not see as much of an improvement in fuel economy with a switch to electrification as LDVs do.

Medium duty trucks that are used for short-haul deliveries do not travel as far between refueling and could potentially benefit from some of these alternative power trains.
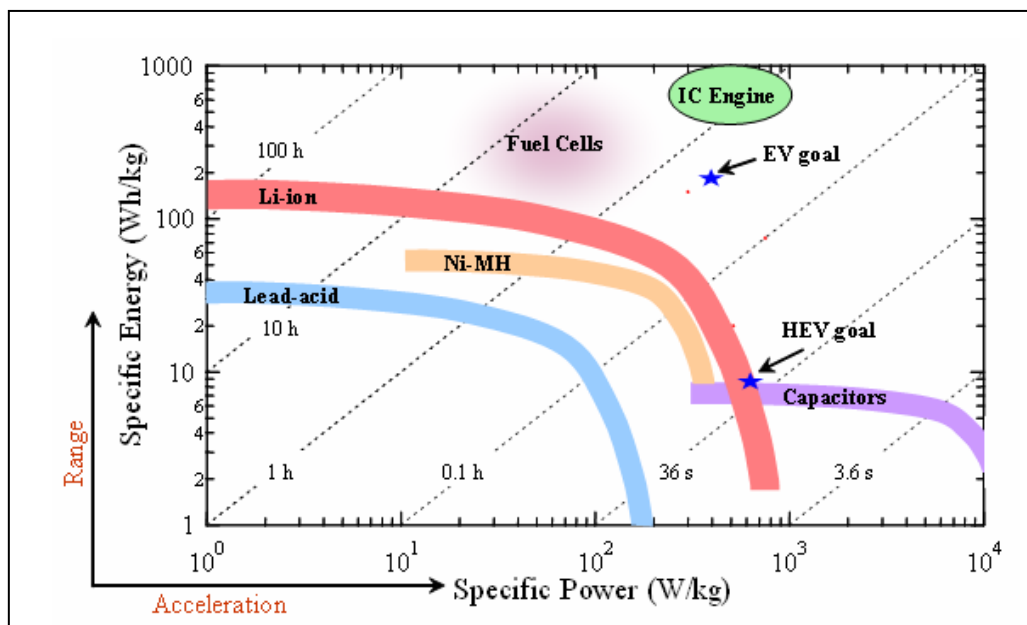
Figure 5-15. *Power and energy density for batteries, fuel cells and IC engines.*

The main approaches to reducing energy use and GHG emissions from long-haul heavy-trucks will come from further improvements to the engine and drivetrain efficiency, other vehicle based efficiency measures (weight, aerodynamics and rolling) and logistics, rather than from adopting advanced electric or fuel cell drivetrains. Use of compressed natural gas fuel was not considered for heavy duty transport, but may offer further potential to incrementally reduce CO2 emissions.

5.3.1 Approach and Data sources

A spreadsheet model is used to develop scenarios for energy/fuel use for several classes of trucks. Data for truck activity in California is derived from the California Department of Transportation's MVSTAFF model report (Caltrans 2008). This analysis projects VMT, fuel usage and fuel economy for different truck classes to 2030. It breaks vehicles into several different categories (automobiles, motorcycles and 4 classes of trucks). Trucks considered in this section are in the 3rd and 4th categories, which will be called medium and heavy duty trucks. Medium duty trucks are those between 10,000 and 33,000 lbs and heavy duty are those above 33,000 lbs.

The EMFAC program from the California Air Resources Board also breaks down trucks into several categories and tracks miles, fuel consumption and emissions. It contains five categories of trucks (medium duty trucks, light heavy duty 1, light heavy duty 2, medium heavy duty and heavy heavy duty). The last three categories correspond with categories 3 and 4 from the MVSTAFF, which cover trucks heavier than 10,000 lbs. It is presumed that trucks below 10,000 lbs are passenger vehicles and used for personal and light commercial use.

5.3.2 Vehicle efficiency

Caltrans MVSTAFF model provided the fuel economy of each of the 4 types of trucks in 2010. Projections for efficiency improvements from a number of different mitigation options were considered with respect to each vehicle type. The main improvements resulted from improving the vehicle drivetrain (including engine, transmission, hybridization, and idle reduction), road load reductions (improvements in aerodynamics, rolling resistance, reduced weight) and operations (speed reduction and driver training).

All large long-haul trucks are assumed to continue to operate with diesel engines and liquid fuels while many of the smaller short-haul trucks are assumed to be able to electrify to some extent. For those vehicles that continue to run on diesel-like liquid fuels, they are able to reduce their energy intensity by 29% and 57% from the 2010 truck fleet for long and short-haul trucks respectively. The greater improvement in short-haul efficiency results from a greater benefit to hybridization, since short-haul trucks travel shorter distances and do more city driving. Long-haul trucks benefit more than short-haul trucks with respect to aerodynamics and speed reduction but these lead to much smaller improvements than hybridization.

Finally, nearly half of short-haul trucks are assumed to be able to switch to electric drive trains and operation on grid electricity. They are more likely to be found in smaller trucks (i.e. medium duty).

These trucks achieve a reduction in energy intensity of 77% (i.e. they use about 1/5 the amount of energy to go one mile) compared to 2010 truck fleet.

This scenario assumes that electrified trucks make up 47% of class 3 trucks and 0% of the larger class 4 trucks. Of these electrified vehicles it is assumed that half of the miles are powered by electricity in 2050. Thus, approximately 24% of class 3 truck miles are powered by electricity in 2050.
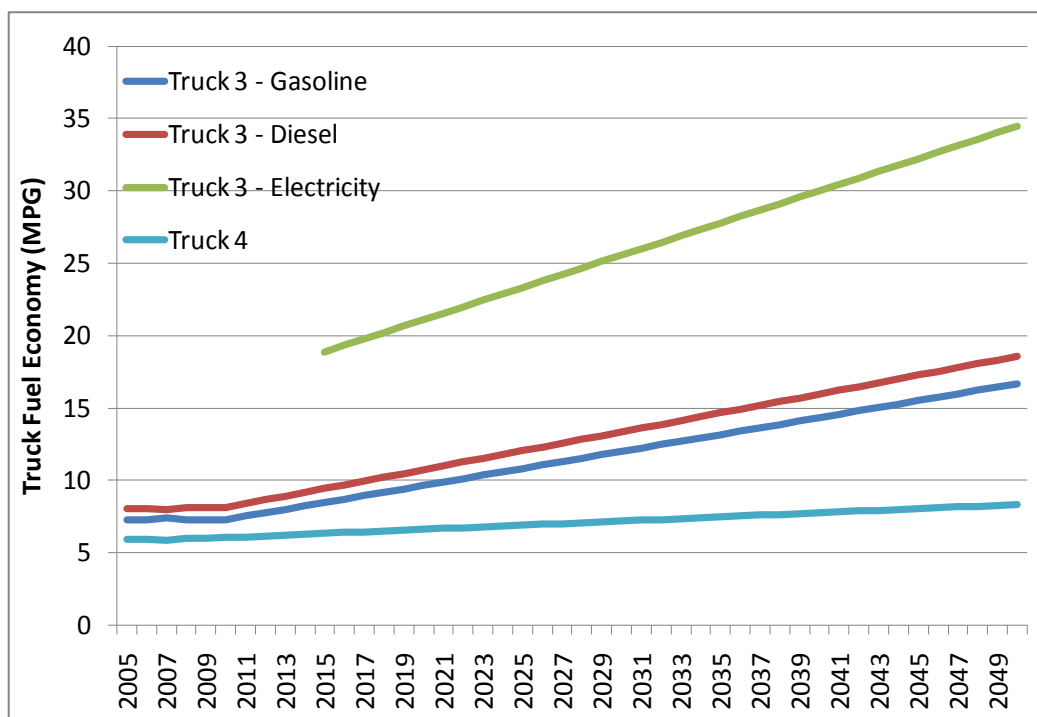
Figure 5-16. *Fuel economy of heavy duty trucks*

5.3.3 Travel demand

Projections for truck vehicle miles traveled were taken from the Caltrans MVSTAFF model out to 2030 and were normalized on a per capita basis. The model breaks down each class of trucks into gasoline and diesel versions, each with a separate travel demand. So the model essentially tracks four different vehicle classes. The trend in per capita travel demand for each of the different truck classes were linearly extended to 2050. These values were multiplied by the state forecast for population to get the total VMT for each truck class to 2050.

From 2010 to 2050, total truck VMT is expected to increase significantly, essentially doubling - class 3 trucks increase by 96% and class 4 trucks increase by 123%. Total miles for both classes of trucks increase 108%, from 23.6 billion VMT to 49.16 billion VMT. This results from a 37% increase in per capita truck miles and a 52% increase in population from 2010 to 2050.
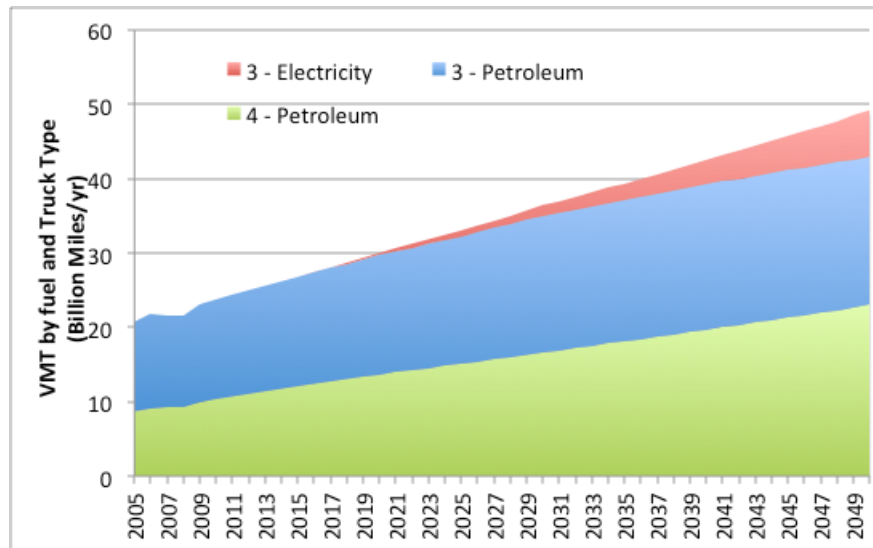
Figure 5-17. *Statewide travel demand for medium and heavy-duty trucks.*

5.3.4 Fuel Use

Based upon the increase in VMT and reduction in energy intensity of trucks, total fuel use is increases about 35% from 2010 to 2050.

The make-up of fuels is slightly different. Gasoline usage is reduced somewhat while electricity usage is increased to about 6000GWh, but diesel-like fuels remain the largest share of fuel consumption (~90%).
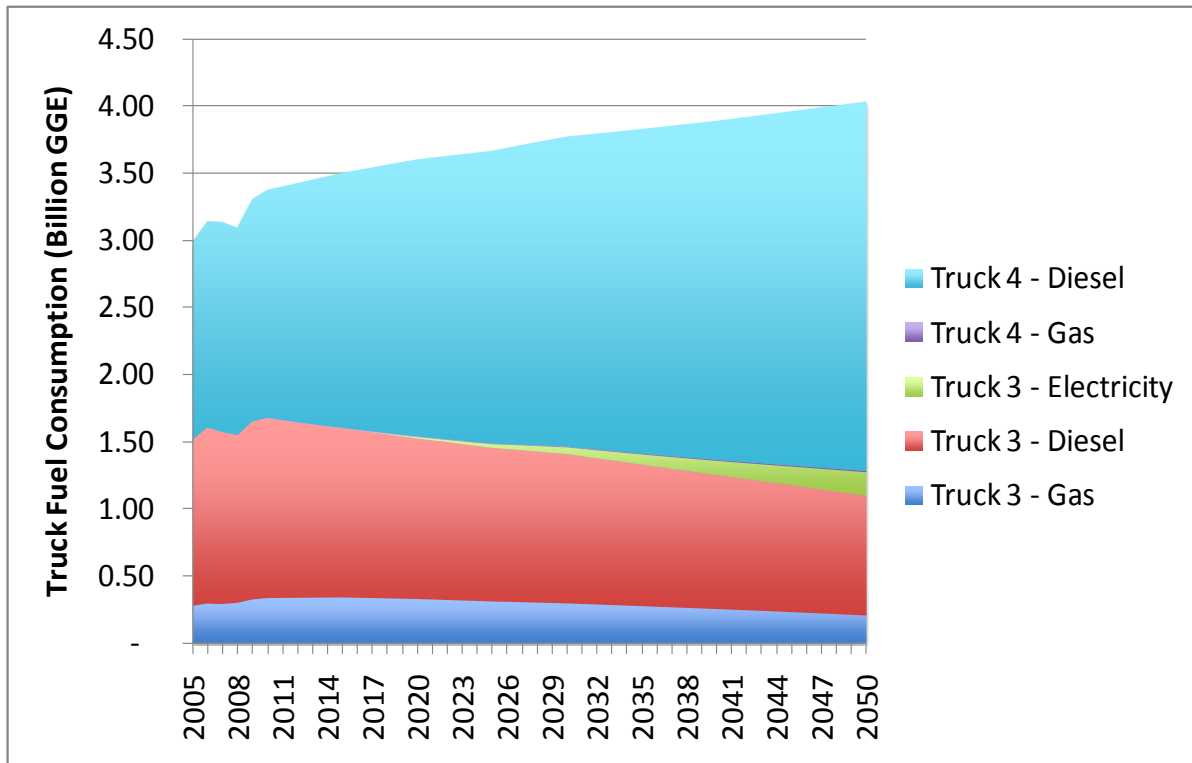
Figure 5-18. *Fuel usage for medium and heavy-duty trucks.*

5.4 Aviation

Passenger and freight aviation is a growing transportation subsector. Of the major transportation subsectors, travel demand is the most uncertain in this subsector because of the high elasticity of aviation travel.

This analysis categorizes three types of passenger travel – intrastate, interstate and international flights and two types of freight travel – instate and out-of-state flights. Projections for demand are made in each of the travel categories. An estimate was made by the author for the mix of planes that is used in each of the three categories of travel. Aircraft fall into three categories: narrow-body aircraft, wide-body aircraft and regional jets. Each type of plane has a different efficiency (in terms of seat-miles per gallon) and thus the three categories of travel will vary in terms of their efficiency based upon the mix of aircraft that are used (e.g. international flights typically use larger planes that hold more passengers than shorter in-state flights).

5.4.1 Approach and Data Sources

Scenarios are developed for the vehicle efficiency of new planes of each type and their travel demands over time. These assumptions are then input into a stock turnover model for California

aviation that tracks the types of planes that are used, their mileage and efficiency. The output of this model is fuel demand for each travel category.

Data for aviation travel demands include DOE's Annual Energy Outlook (AEO2010), USDOT's Bureau of Transportation Statistics (BTS 2011) and the California Air Resources Board's emissions inventory (ARB 2010A). The potential for aviation efficiency improvements is obtained from several sources, including McCollum 2009, and IEA 2008.

5.4.2 Vehicle efficiency

Fuel consumption can be reduced by improving propulsion efficiency, improving aerodynamics, lightening the aircraft and operational improvements. Figure 5-19 shows the fuel consumption per passenger kilometer for different aircraft and the US fleet average over time.

Notes: 1) The bar for each aircraft reflects varying configurations; the line shows estimated fleet average for the United States across all existing aircraft. 2) RPK = revenue passenger kilometre = number of passengers carried x distance flown (in km).
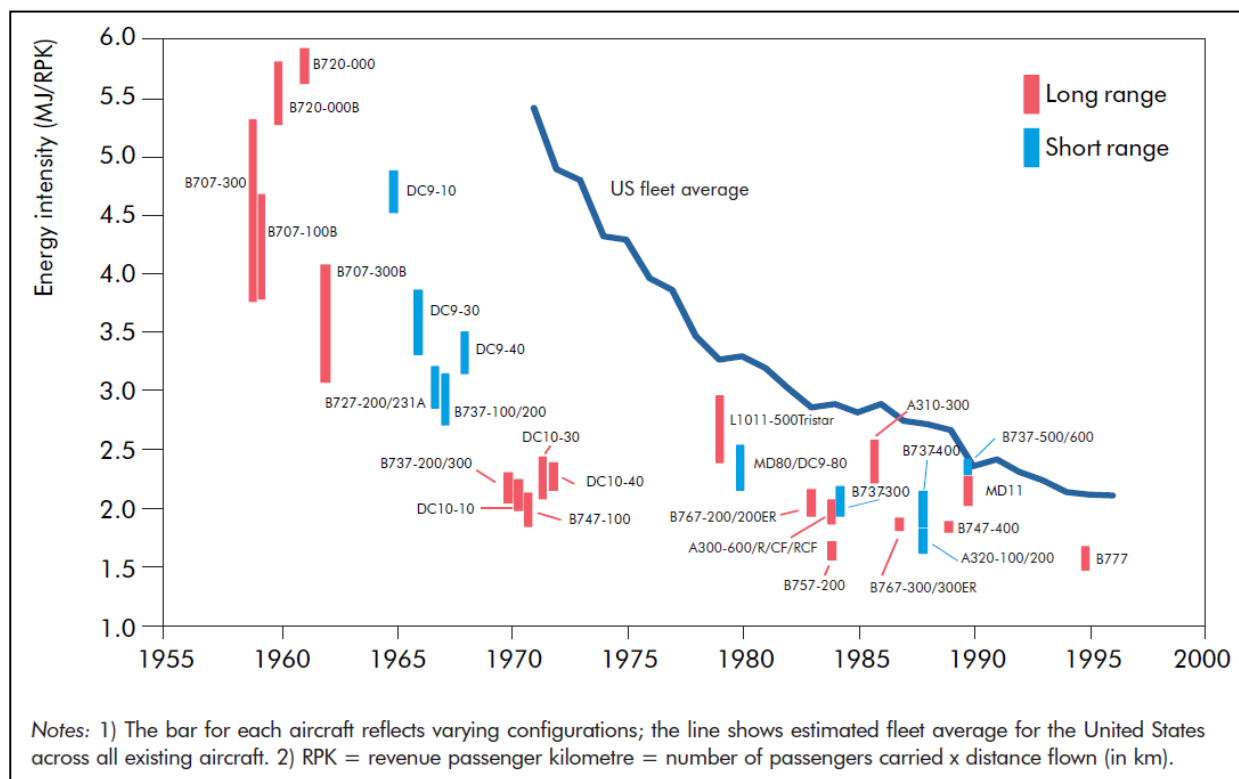
Figure 5-19. *Historical aircraft energy intensity, new aircraft and U.S. fleet average (Source: (IEA 2008b)*

Fuel efficiency of conventional aircraft have been improving continuously for many years and the rate of improvement has slowed. Fleet turnover, which retires older, less efficient aircraft will also continue to bring down the energy consumption in the fleet. Because fuel is a major cost element for airlines, there is a strong incentive for fuel efficiency improvements and it is expected, even in the absence of significant policy, new aircraft energy intensity (energy/passenger mile) will

continue to decrease by about 1-2% per year and a total reduction in fleet average energy intensity by 30% by 2050. This level of reduction is expected from the use of more efficient jet engines, advanced lightweight materials, and improved aerodynamics (e.g., winglets and longer wingspans) (IEA 2008; Schäfer, Heywood et al. 2009). These technologies have already been demonstrated and employed on existing state-of-the-art aircraft, (Airbus A380, and the future Airbus A350 and Boeing 787).

Beyond these expected changes, additional improvements can be made to increase fuel efficiency. These include advanced jet engines, laminar flow control and more substantial changes/redesigns such as blended wing aircraft designs and these options have the combined potential to decrease energy intensity by an additional 35%. With these aggressive changes, it has been estimated that fleetwide energy intensity could be 70-80% lower (McCollum et al. 2009). However, it is expected that these more aggressive changes could lead to an abatement cost of more than $110/tonne CO_2 and as a result may not be cost effective unless very strong carbon policies are put in place.

Operational changes to how aircraft are operated include improved air traffic management and optimized flight paths, communications and navigation systems, and changes in aircraft descent patterns. Improvements in these operational elements are expected to reduce global aircraft energy use by 10% in 2050.

This analysis assumes that aggressive changes to new aircraft lead to improvements in fuel efficiency such that new planes in 2050 achieve a 60% reduction in fuel consumption per seat mile relative to planes in 2000. Because of the lag in fleet fuel economy, this translates to a 47% reduction in fleet fuel consumption per seat mile from 2008 to 2050.
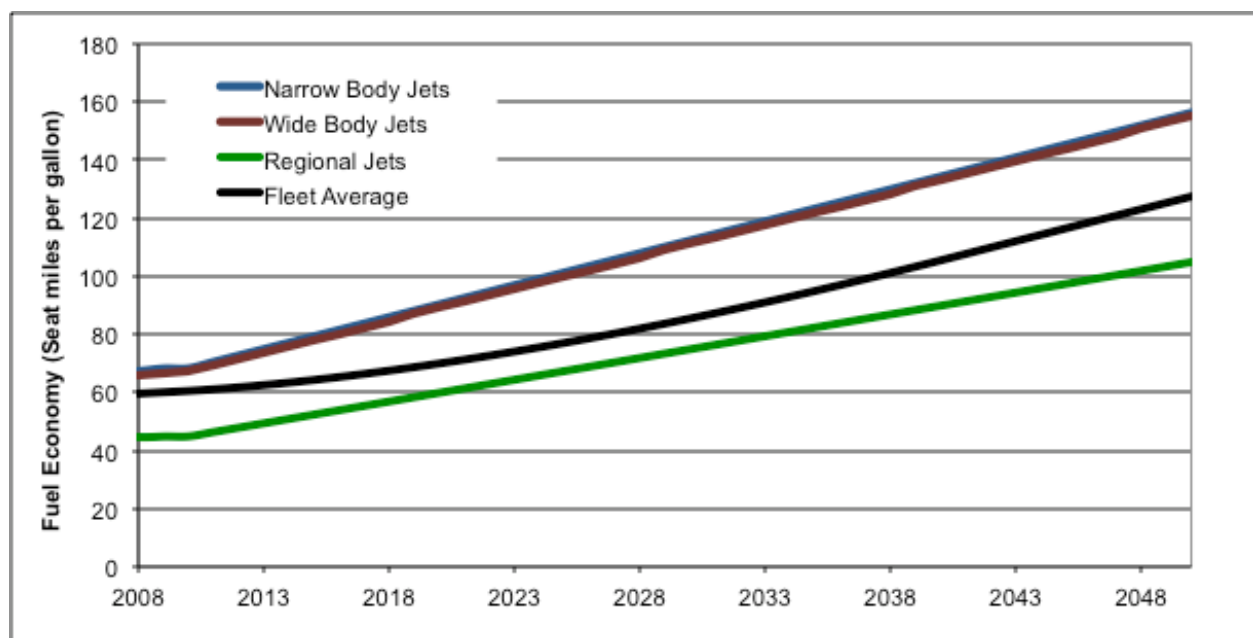
Figure 5-20. *Fuel economy of new planes over time and fleet average.*

5.4.3 Travel demand

Travel demand for aviation is highly uncertain as it is fairly elastic. Elasticity is higher for short flights because of substitutability, with other modes of transport. Business travel is relatively inelastic ($E_d > -1$), while most other types of flights tend to be relatively elastic ($E_d < -1$). Because of the price-sensitivity of air travelers, there is significant uncertainty about the future growth of air travel, especially in the face of uncertain economic growth, future oil prices, fuel and carbon policies and other factors. The projected annual growth rate for passenger travel in AEO projections, which extend 20-25 years into the future, has declined significantly over the last decade, mainly because of macroeconomic factors including oil prices.

	Passenger seat miles annual growth rate (%)	End Year
AEO 1999	3.8%	2020
AEO 2004	2.3%	2025
AEO 2007	1.6%	2030
AEO 2010	1.35%	2035

Table 5-1. *Passenger seat mile growth rate projections.*

This analysis uses the relatively conservative projections of per-capita air travel growth from the reference case in AEO 2010 to 2035, which are then extended out to 2050. The annual growth of per capita travel for the US from AEO is applied per-capita air travel data from California. However, because the reference case does not assume significant policies to reduce carbon emissions, projected demand could vary significantly due to high price elasticity from rising air travel prices.

From the 2008 ARB emissions inventory and an estimate of the breakdown of plane types used to meet the three different types of passenger travel, an estimate for the number of miles flown in each category of travel is made.

Intrastate travel (flights originating and ending in California) makes up a small percentage of total aviation travel (~7%). Interstate travel (flights that have an origin or destination, but not both, in California, and are domestic) make up about half of total aviation miles (~51%) and 43% of miles comes from international flights with an origin or destination in California. Regional jets are estimated to make up about 4% of total seat miles, narrow body jets, 64%, and wide-body jets about 32% of total seat miles for California.

Breakdown of Seat Miles (Billions) into Distance and Jet-type Categories					
	Regional Jets	Narrow Body	Wide Body	Totals	Percentage
Intrastate	3.5	10.5	0.0	14.0	6.9%
Interstate	5.2	93.0	5.2	103.3	50.6%
International	0.0	26.0	60.7	86.7	42.5%
Totals	8.7	129.5	65.9	204.0	
Percentage	4.2%	63.5%	32.3%		

Table 5-2. *2008 Breakdown of Miles for three categories by type of jet.*

ARB only counts emissions from intrastate travel (which makes up 7% of seat-miles). Because out-of-state travel (i.e. interstate and international trips) have an origin or destination in another location, only half of the miles and fuel use is attributable to California. The table above and the ARB emissions inventory reflects this. Thus, there can be a factor of around 17 in aviation seat miles (and a similar factor for energy usage and emissions) between considering only intrastate travel and considering all aviation travel related to California travel.
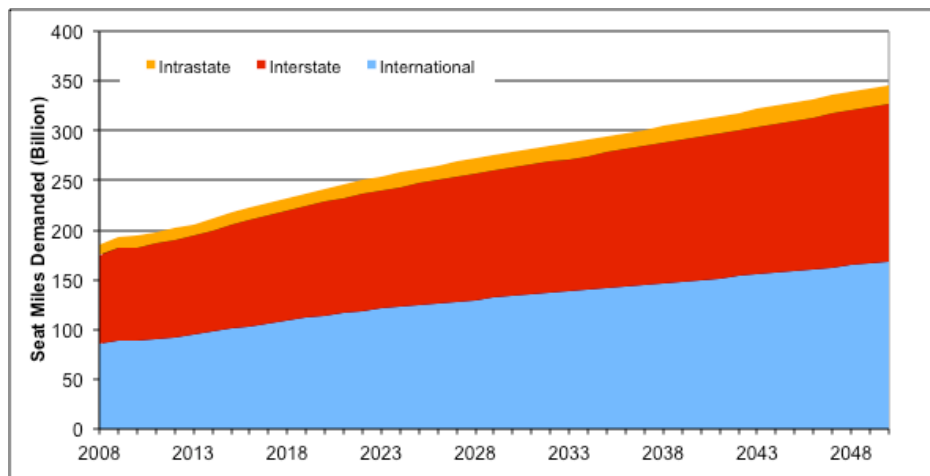
Figure 5-21. *Projected passenger seat miles demanded for three travel categories in California.*

5.4.4 Freight

Freight shipping is another key contributor to energy use in aviation and is tracked in terms of ton-miles traveled. However, there is some overlap in energy use between freight and passenger aviation since cargo is sometimes carried on commercial passenger flights. According to BTS

statistics about half of passenger flights carry some cargo as well. It is assumed that energy use for passenger flights that also include cargo is entirely attributed to the passengers. Thus, only a fraction of freight shipments (ton miles) are counted when tracking freight energy usage, estimated to be around 50%.

Demand for freight shipping is assumed to grow on a per capita basis out to 2035 according to the AEO2010. This per capita growth rate is extrapolated to 2050 and applied to California's projected population to 2050. This leads to a growth in total ton miles shipped of 120% from 2008 levels in 2050. Out-of-state freight shipping makes up about 99% of total freight ton-miles shipped. Freight cargo planes are also assumed to improve in efficiency at the rate of passenger planes.

5.4.5 Fuel switching

A recent NASA study (NASA 2008) concluded that Fischer-Tropsch (FT) fuels are chemically a viable drop in replacement for jet fuel. They have good thermal stability, contain no sulfur, and produce less particulates and fuel system deposits. FT fuels can be made from any hydrocarbon source, including natural gas, coal, biomass and even biogas and synthetic methane (CO_2 + hydrogen).

Aside from FT-fuels derived from biomass, more conventionally produced biofuels (such as biodiesel) are not as well suited for jet fuels, mainly due to freeze tolerance issues. Jet fuels need to withstand freezing at very low temperatures (-40C and below). Fuels tailored to meet jet fuel specifications, called biojet are being developed and are getting closer to being useable in aviation applications. Another key challenge for biofuel usage relates to biomass resource limitations.

The prospects for the use of non-liquid fuels (either gaseous or electricity) in jet engines appear to be quite limited.   This analysis calculates jet fuel requirements on an energy equivalent basis (gallons of jet fuel energy equivalent), since FT and bio-based fuels will typically have lower energy content per unit volume than a petroleum based fuel.

5.4.6 Total fuel consumption

Significant increases in aircraft passenger travel demand (86% increase) and freight transport demand (120% increase) from 2008 levels to 2050 and significant decreases in fuel consumption per passenger mile and per ton-mile (47% decrease) leads to slight decreases in overall fuel use over the 2008 to 2050 time period. Passenger aircraft fuel demand decreases from 3.1 to 2.7 billion gallons per year while freight fuel demand remains relatively constant at 0.7 billion gallons per year.
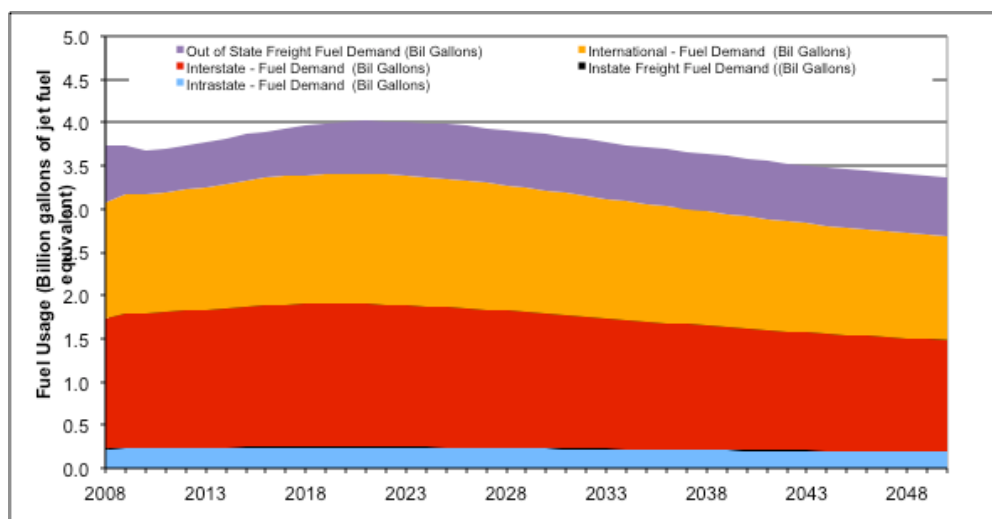
Figure 5-22. *Fuel consumption for different categories of passenger and freight aviation transport.*

5.5   Marine

The marine subsector encompasses several categories of vessels including large ships for the movement of freight, commercial fishing, and passengers, as well as smaller harbor craft such as work or tug/tow boats, ferries and personal recreational boats. Large marine vessels are an integral part of the global supply chain for goods and freight movement. Nearly all large ships are powered by diesel engines running on marine diesel oil or heavy residual fuel oil. Large ships account for most of the marine miles and energy usage, compared to harbor craft and personal boats. Smaller boats, particularly personal boats, can run on gasoline as well. Like aviation and heavy duty trucks, it is expected that the marine subsector will continue to run primarily on liquid fuels in various types of combustion engines.

As with aviation, marine travel can fall into several categories based upon travel in relation to state boundaries; intrastate, interstate and international.

Marine accounts for nearly 13% of total energy use and GHG emissions from transportation in California.

5.5.1 Data sources and approach

The California Air Resources Board's emissions inventory breaks up fuel usage in state by type of fuel used and into three travel categories. International marine fuel usage is the largest component of total marine fuel usage (87%), while intrastate and interstate marine shipping makes up 11% and 1% of total fuel use respectively. Thus like aviation, most of marine fuel usage and greenhouse gas emissions are "excluded" from a state emissions perspective. However, these sources can contribute a great deal to total statewide fuel usage and require fuel production and delivery infrastructure.

This analysis breaks these marine vehicles into two categories, Ocean going vessels and harbor craft. Given the fraction of fuel used for international shipping, ocean going vessels make up most of the fuel consumption. The potential efficiency improvement from these two vehicle types is estimated and applied to the fleet out to 2050.

5.5.2 Vehicle efficiency

Marintek (2000) and McCollum (2010) provide a good review of potential options for reducing GHG emissions from marine travel, focused mainly on ocean going vessels. Ship efficiency can be significantly increased by increasing ship sizes, hull and propeller optimization, engine efficiency improvements and low resistance hull coatings. Doubling the size of a ship has the potential to reduce drag forces by 30%, though practical limitations exist, which prevent ships from becoming too large. Optimization of hull, propeller and engines can improve efficiency by 40%. Additionally, operational changes, including speed reduction, and optimized routing can reduce fuel usage up to 50%. Based upon these potentials, ocean going vessels were assumed to be able to reduce fuel consumption per ton-mile carried by about 55%.

It was assumed that harbor craft have fewer options for reducing energy usage since they are not traveling long distances and have irregular duty cycles. By 2050, harbor craft energy usage per mile is assumed to decline by 25%, which would be representative of standard engine improvements.

5.5.3 Travel demand

The DOE's Annual Energy Outlook and DOT's Bureau of Transportation Statistics were used to calculate US ton-miles of marine shipping. A per capita value (ton-miles per person) was calculated from the AEO projection to 2035, which was extrapolated to 2050. Per capita ton miles are expected to decline 21% from 2008 to 2050, which when coupled with population growth amounts to a 23% increase in total ton-miles in California over the same time period. Harbor craft activity is expected to increase proportional to total ocean-going traffic.

5.5.4 Total fuel consumption

Greatly improved marine vessel efficiency and a slight increase in total ton-miles and harbor craft activity lead to a substantial reduction (36%) in total marine fuel demand in 2050 relative to 2008. The vast majority of fuel demanded is related to out of state travel (87%).
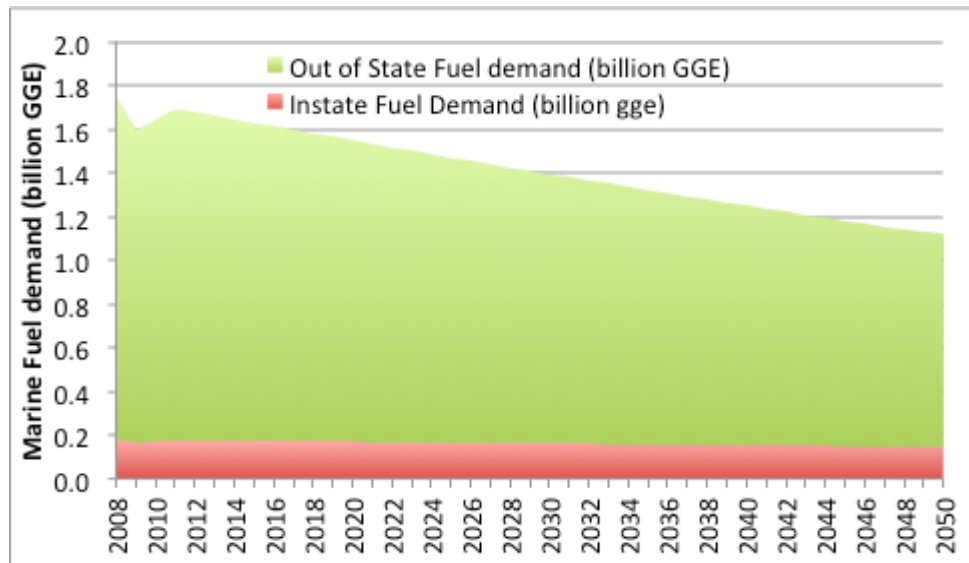
Figure 5-23. *Marine fuel demand projection to 2050.*

5.6   Bus

Buses are passenger vehicles, typically organized as a public transportation system either as city transit, intercity service or school buses. Buses and their engines receive a great deal of wear because they are often driven continuously over the course of the day with significant starts and stops. Consequently, durability, efficiency, and fuel costs are important considerations. Buses have primarily used diesel engines in the past, though air quality concerns have induced some municipalities to switch over a portion of their bus fleets to cleaner alternatives, such as natural gas.

Buses account for a small fraction of total energy and GHG emissions in California (~3%).

5.6.1 Data sources and approach

Data on US based bus travel is found from the American Public Transportation Association (APTA 2011), which provides information on energy efficiency, load factors and travel demand. This data is scaled to California. A scenario is developed regarding bus efficiency and fleet share from different drivetrains, and is used to calculate fuel usage. Figure 5-24 shows the assumed fleet share of each bus drivetrain type in California. Electric buses achieve approximately a 50% fleetshare, while diesel hybrid buses make up the remainder of the fleet.
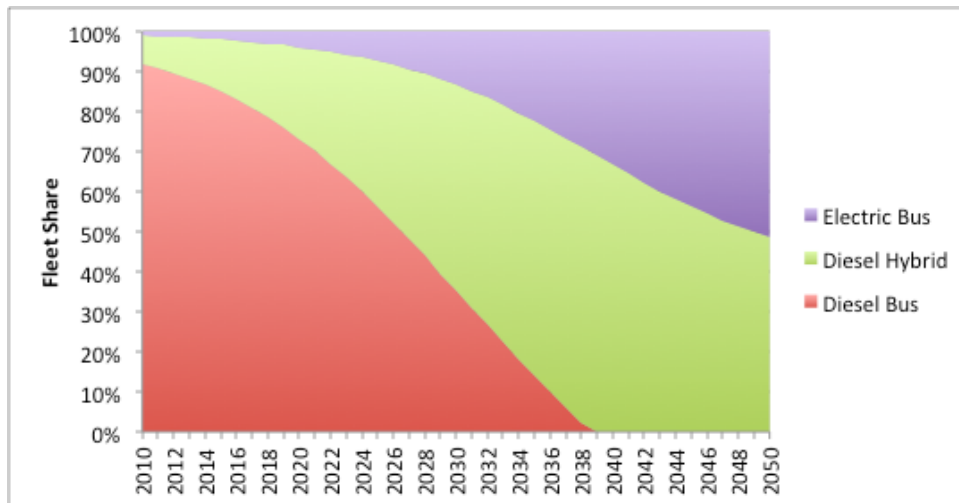
Figure 5-24. *Fleet share by bus drive train type.*

5.6.2 Vehicle efficiency

Buses, like heavy trucks and light-duty vehicles, can improve efficiency via advanced propulsion systems (hybridization, plug-in hybrids, fuel cells, and all electric drivetrains), reducing weight, aerodynamic drag and rolling resistance.

The fuel economy of diesel buses is expected to increase from 3.6 mpg to 4.6 mpg (28% improvement) from 2010 to 2050 while diesel hybrids are expected to increase from 4.7 to 5.9 mpg, and electric buses can achieve 8.3 mpgge in 2050. The switch from diesel buses to a combination of diesel hybrids and electric buses leads to a significant improvement in bus fuel economy, from 3.7 mpg in 2010 to about 7 mpgge in 2050 (89% improvement).

5.6.3 Travel demand

Travel demand, in terms of vehicle miles traveled by bus, is dependent upon two factors: population, passenger miles traveled per capita and load factor[13]. The latter two of these factors (passenger miles per capita and load factor) are assumed to be constant in this analysis, such that the main driver for overall travel demand growth is population growth. Total passenger miles grow from 19.5 billion passenger miles in 2010 to 29.7 billion passenger miles in 2050.

While not included in this scenario, the demand for buses could increase significantly if significant personal automobile traffic were shifted to transit modes (including rail and buses). This would be especially true in higher density urban areas where congestion and parking issues make single occupant car travel less convenient and expensive and transit more attractive.

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[13] Load factor represents the number of passengers on a vehicle and thus represents the number of passenger miles that can be served based upon a vehicle mile traveled.

5.6.4 Fuel usage

Overall fuel use by buses declines in this scenario about 20%, though the amount of diesel (i.e. liquid fuel) declines by 54%. Electricity grows to be a major energy use in bus transportation accounting for 200 million gge (or 6618 GWh), which is approximately 2% of total electricity demand in California in 2010.
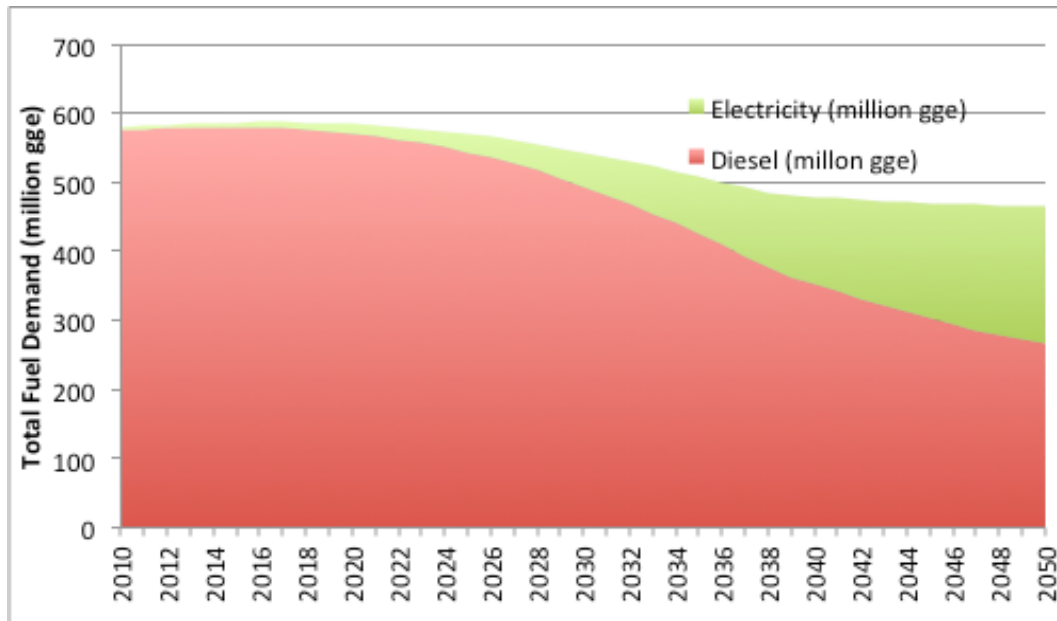
Figure 5-25. *Fuel usage by fuel type for buses.*

5.7   Rail

Rail transport consists of trains that are typically powered by diesel or electric locomotives and carry passengers and freight. The majority of rail energy usage results from the movement of freight, but passenger travel also accounts for a significant portion of rail energy use. Passenger rail is broken into several categories including intercity, commuter, light, and heavy rail. Current passenger rail usage is relatively small, but because passenger rail is one form of public transportation, a significant shift in personal mobility from automobiles to rail could lead to a rapid increase in the usage and energy requirements of rail transport. Freight transport is expected to increase in the future even without mode shifting.

Passenger and freight rail make up about 0.3% and 0.7% of energy use and GHG emissions of the California transportation sector.

5.7.1 Data sources and approach

Data for US rail transport are primarily derived from Oak Ridge National Lab's Transportation Energy Data Book (ORNL 2011), which provides information on passenger and freight rail miles, energy use and vehicle miles. This data is then scaled for California's share of rail transport.

Similar to the approach from other sectors, total fuel demands for rail transport will be a function of the passenger and freight rail travel demand, passenger car load factors, changes in rail engine efficiency, and switches in rail propulsion systems/fuels.

In this analysis rail transport is broken into four categories: Amtrak/intercity, commuter, transit and freight rail.

5.7.2 Vehicle efficiency

A number of strategies exist for improving freight and passenger rail efficiency, including reducing train weight, reducing aerodynamic drag, lubrication, traffic management, better power and traction management and regenerative braking. These technologies can improve the efficiency of the passenger rail fleet by about 50% from 2010 to 2050 while switching from conventional diesel locomotives to electric locomotives can approximately double the energy efficiency of train travel depending on the category of travel. Transit rail is primarily run on electricity already so there is less efficiency improvement potential. All trains in California are assumed to be able to switch to electric locomotives powered by overhead lines or a third rail.

5.7.3 Travel demand

Like bus travel, travel demand for rail is dependent on population, passenger and freight demands per capita, and load factors. As with buses, per capita miles and load factors are held constant in this analysis, so rail travel demand is assumed to scale proportionally with population growth.

While not explicitly included in this scenario, the construction and utilization of a high-speed rail system in California could significantly increase the amount of intercity rail usage by an order of magnitude or more.

5.7.4 Fuel usage
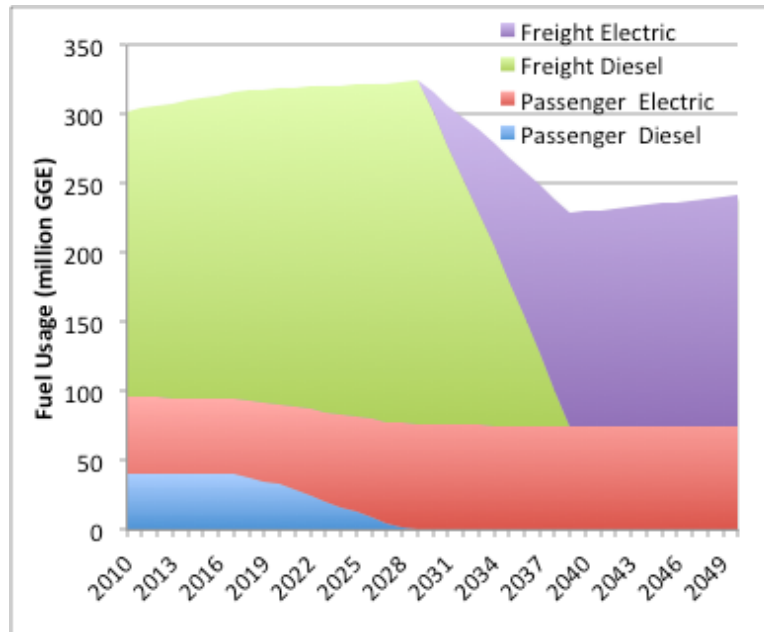
Figure 5-26. *Fuel used for rail travel in California.*

Overall fuel demand from rail transport declines about 20% from 2010 to 2050, though it switches from primarily diesel fuel to entirely electricity. The switch to electrified trains is expected to happen a little bit earlier for passenger rail than for freight rail.

6.   INDUSTRY

6.1   Introduction

The treatment of long term industrial energy use is challenging because of the heterogeneity of industry sectors and applications and the dynamic nature of the economy. Overall there is a wide range of estimates for the U.S. in industry growth and concomitant energy consumption.   For example, there is a wide range of estimates for long term (2035) industry electricity use by up to 50% between the most recent AEO 2011 projections and other long range studies.   These differences stem from differing assumptions about overall GDP and industry sector growth, different energy efficiency assumptions, as well as different fuel switching assumptions. For example, AEO 2011 projections assume lower electricity demand from the previous year's projections due to growth in combined heat and power[14], whereas in this study we move in the opposite direction to minimize fossil fuel carbon emissions. Intra-industry sectoral change is also major contributor to overall industry energy use with a trend toward more off shoring of industrial activity and a shift to the less energy intensive service sector.

For industry, as opposed to the building sector, there is a large rate of "autonomous" energy efficiency (often assumed at 1% per year normalized to GDP growth), or natural growth of energy efficiency gains apart from policies and programs external to industry, since industry has a bottom line incentive to be more energy efficient.

The methodology for this report is to aggregate all the energy efficiency improvements that are technically possible relative to a frozen efficiency case to determine a technical potential case. This means that we are not counting items that could improve energy consumption like product design and continuous product improvement that can indirectly improve energy consumption, so our estimate may underestimate overall energy demand reduction. We follow this approach since it is possible to count the direct EE savings measures but less certain how to account for "indirect" EE savings.

For California, CO2 emissions in the state from industry have been flat to slightly falling (4% drop from 2000-2008), and are projected to be flat to 2020 in CARB state projections. Industrial activity and GHG emissions are dominated by the oil and gas industry: extraction and refining account for about 60% of overall energy consumption despite dropping in state crude oil production, with natural gas and refinery gases the primary fuels.   Oil extraction is highly energy intensive with thermally enhanced oil recovery (TEOR) recovery techniques commonly practiced in the state.   The oil and gas industry also represents about half of the states industry CHP and consumes oil refinery gases and petroleum coke in addition to large quantities of natural gas.

However, both in-state oil and gas extraction has been decreasing in California and expected to continue to decrease. 87% of natural gas is imported today and is expected to continue dropping to

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[14] Greater on-site combined heat and power would reduce grid electricity demand. In the case of natural gas fueled CHP, offsite electricity is typically replaced with on-site power generation and waste heat utilization and much higher efficiency is achieved. On-site gas usage would increase but total system wide energy would decrease.

2050 (CPUC 2010), and in state crude oil production has been decreasing by about 2% annually over the last 20 years, while foreign crude oil has increased sharply (Figure 6-1).
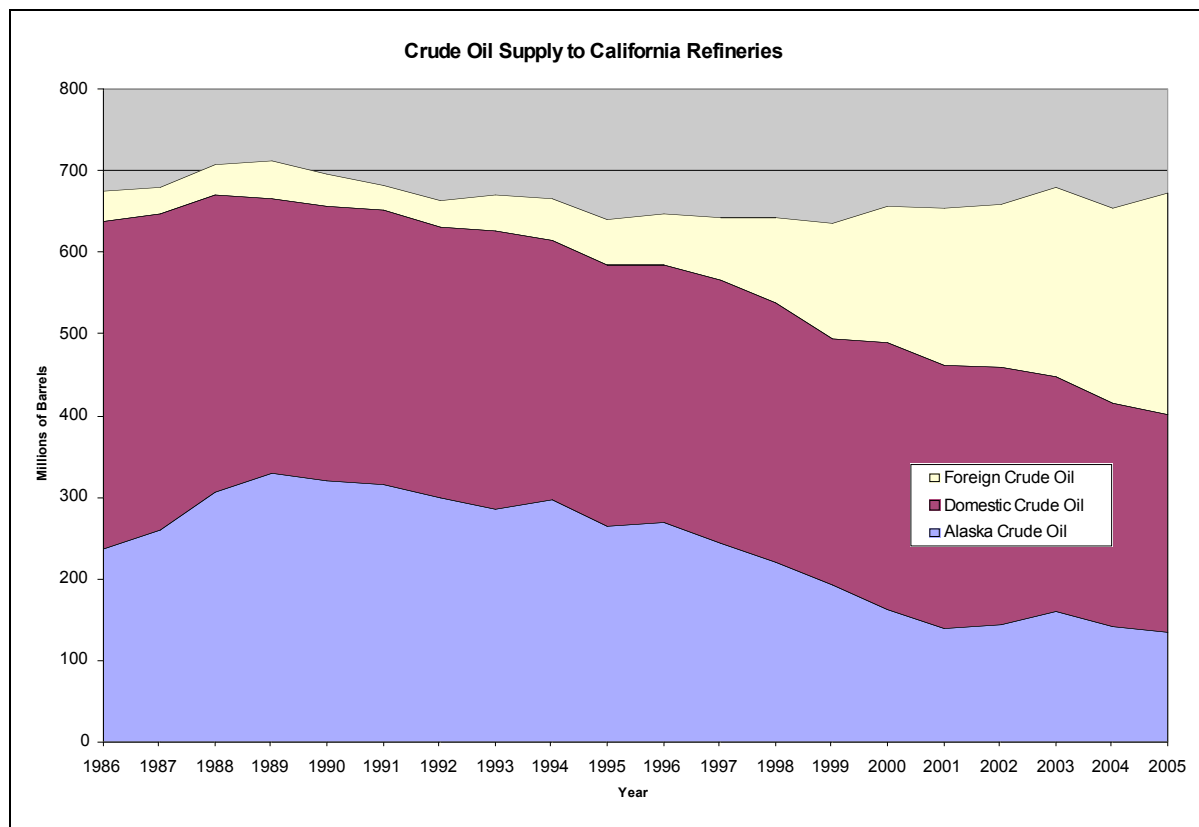
Figure 6-1. *Domestic (in-state) crude oil supply to California refineries has been shrinking over the last 30 years. (Sheridan 2006).*

Non-oil and gas manufacturing sector fuel usage is less than a third of oil and gas fuel usage. Overall energy consumption for electricity represents about 28% of overall energy consumption.

Other large energy consuming industries include the food industry (spanning food, beverages, sugar refining and fruits and vegetables), chemicals, and glass and clay products. The food industry represents 7% of overall energy or 17% of non-petroleum industry energy. Cement manufacturing is also a significant contributor to manufacturing emissions although a smaller relative fraction of energy consumption.

6.2   Short Term Energy Savings

Short term energy savings are projected to 20-30% over the next 10 years depending on the application, mainly from operational practices and improved maintenance and without high capital expense or a significant amount of equipment replacement. An example is provided for the process

heating segment in Table 6-1 (DOE 2007a). "Low hanging fruit" includes air/fuel optimization, wall heat insulation and advanced controls as well as incorporating other best operations and best maintenance practices. Further retrofitting work can be done such as the installation of advanced burners, and preheating of combustion air or incoming load to bring cumulative savings above 30%.

Similar short term energy savings can be realized in steam and motor systems from maintenance, operational measures, and control measures without major capital investment. For boiler use and steam systems there are opportunities on the distribution side such as thermal recapture at the backend of steam systems while maintenance items such as faulty valves, and system related problems can also yield large savings. For motor systems, an estimated 20% savings can come from routine maintenance while for applications with variable loads, larger savings (up to 50%) can be realized with the adoption of variable speed motor systems.

Measure	Individual savings	Cumulative savings
Air/fuel ratio optimization	5%	5%
Wall heat losses	2%	7%
Furnace heat transfer	5%	12%
Advanced burners/ controls	5%	16%
Preheat combustion air	15%	29%
Fluid or load preheating	5%	32%

Table 6-1. *Process heating savings measures that can be implemented in the short term.*

A sampling of other energy efficiency examples in industry is given here to illustrate the wide nature of applications and opportunities:

- Existing plants in the pulp and paper industry feature waste heat recapture (e.g. increased heat recovery of steam used to dry the paper with closed hood heat exchanger for water pre-heating or air pre-heating for a 15-20% increase in energy efficiency)
- Mechanical vapor recompression in chemical distillation processes that are in production can give coefficients of performance from 3-5 versus fossil fuel efficiency without recompression ~ 80%.
- Membrane separation for various chemical, petroleum and food processes move production from high temperature thermal distillation processes or boiling/evaporation to electricity pump-driven membrane separation systems. Efficiency gains of up to 40% can be realized. This technology is starting to be utilized but not yet in wide scale manufacturing.
- Solar thermal concentration systems for low pressure steam are utilized in the food/beverage industry, for example at a Frito Lay plant in Modesto. Issues here include cost, seasonal variation of solar irradiation, and the need for backup boilers.
- Further out, process intensification in the chemical industry can yield 50-80% savings for selected processes but this may be a decade or more before reaching commercial

application. By combining the chemical reaction and separation in one reactor, capital costs are reduced and energy efficiency is improved through better integration of these process steps and more compact reactors (e.g. reactive distillation).

6.3   Industry Electrification

We assume that there is a shift to electrified process heating in 2020. This is an area where more technology development is needed; while unit processes exist for electric heating (microwave, plasma, RF, induction techniques), large scale electrification requires design and development of integrated electric heating systems tailored to the industrial application. While some development has occurred in the past, it is currently not area of focus for R&D and pilot programs or increased funding would be needed to enable this.

Some industry sectors may also be more amenable to electrified heating especially those with lower temperature heating and drying requirements   We studied two large sectors in some detail (food and beverages, plastics and rubber) to try to validate the assumption of large scale electrification technical potential (Brown 1996). For example, food and beverages utilize fairly low process temperatures (230C bread oven, 175C boiler system) and food processing fuel-fired heating should be electrifiable (drying in dairy industry, ovens in baking, snack food, and meat industries, frying in the poultry and snack food industries). Currently electric process heating is just 3.3% of food and beverage heating and electric steam systems and less than 1% of the market nationwide. In the plastic and rubber sector, process heating electrification potential is similarly large. Fuel based thermal drying at 80C is an opportunity for many products (butyl, polybutadiene, polyisoprene, synthetic EP rubber, dipped latex fabricated rubber, molded latex fabricated rubber). High fuel consumption for curing (150C) is another opportunity for electric replacement.

It is critical to note that in industry, "technical potential" in end use energy efficiency or primary energy use is often insufficient when deciding the desirability of a proposed change and that one must include a systems perspective that can include product quality issues, throughput, process interactions, and other factors.   Metal slab heating for forging provides an illustrative example. Electrical induction heating has lower overall cost despite three times the capital cost and 30% higher energy cost due to material savings with high quality output (less wasted output) and lower operational and maintenance costs than typical fuel-fired slab furnaces (Schmidt 1984).

6.4   Barriers

Barriers to greater adoption of energy efficiency in industry are treated in greater detail elsewhere (e.g. AEF 2009). We touch briefly on the topic here, including barriers to electrified process heating.

Overall key barriers to greater adoption of energy efficiency in industry include:
- Risk aversion is a key barrier especially in low margin manufacturing industries

- Organizational barriers. For example there can be split incentives in organizations where capital spending is different from operations and energy expenditures.
- There is a general lack trained energy auditors and energy managers

The main barrier for electrification is cost and the fact that on a per BTU basis electrically produced heat is 2-4X more expensive than direct fuel based heating systems unless there is inexpensive electricity and/or a high price for carbon. However, energy considerations such as fuel/electricity cost are usually not sufficient to assess electrification potential. Despite the cost barrier, electrified process can offer other benefits (sometimes called "form values") depending on the application: improved product quality, higher throughput, space savings, better process control, and superior directionality.   At the same time design and integration issues must be addressed. Electric systems often require custom design and engineering and low margin or non-advanced technology industry sectors (e.g. glass, food) are not budgeted or staffed for this.

Finally electrification of heating is a new paradigm and industry faces major challenges to meet the targets of this study. There is a lack of an industry electrification "infrastructure" to support a transition away from fossil fuel based heating: shortage of trained personnel within industry, absence of a policy and regulatory framework, and lack of technology development required for electrified system production and deployment.

6.5   Growth Rate Assumptions

For industry-manufacturing growth of fuel, we take industry sector GDP growth assumptions from the recent 2011 PIER study on energy efficiency technical potential for California (Masanet 2011). Industry GDP is projected to grow 1.5% annually to 2050. Frozen efficiency natural gas demand projections are shown in Table 6-2, with projected GDP growth rate per sector and energy demand per unit GDP frozen for each sector. Overall this "frozen" growth in energy is projected to be just over 0.6% per year.   Thus there is almost a 1% annual drop in energy per GDP due to sector change. The sectors in Table 6-2 are listed in terms of energy intensity per GSP and the last column provides the rank of each sector according to annual growth rate. The most energy intensive sectors are seen to have generally slower growth rates (petroleum manufacturing, pulp and paper mills, glass manufacturing), while less energy intensive sectors have faster growth rates (plastics and rubber product manufacturing, chemical manufacturing, and electrical equipment, appliance, and component manufacturing). Thus the overall energy intensity in Energy/GDP is seen to drop over time due to this shift to less energy intensive manufacturing. For the purposes of ARB GHG state accounting, this is favorable but may in effect be shifting emissions or exporting emissions from in-state to out of state.

For industry-manufacturing electricity, the frozen annual growth rate in GWh/year is about 1.4% in California (Table 6-3).   As energy intensive industries are shrinking, higher growth for electricity than fuel is expected.

Description	2006 GSP	2006 Gas Demand [MTh]	2006 Mth/ GSP	Projected GSP ann. growth	2050 Projected GSP	2050 Projected Gas demand [MTh]	Rank by annual growth
Petroleum and Coal Products	3110	571	0.184	0.50%	3873	711	12
Pulp, Paper, and Paperboard Mills	366	52	0.142	-0.27%	325	46	16
Glass	984	115	0.117	-1.55%	495	58	22
Textile Mills	562	55	0.099	-0.82%	392	39	21
Sugar and Confectionary Products; Fruit and Vegetable Processing	3201	265	0.083	-0.76%	2286	189	20
Primary Metal	2561	79	0.031	-0.43%	2116	65	17
Food and Beverage	15812	359	0.023	0.05%	16157	367	15
Nonmetallic Mineral Product (ex. Glass and Cement)	5055	114	0.022	0.93%	7594	171	9
Textile Product Mills	659	13	0.019	-0.61%	503	10	18
Cement	2462	45	0.018	1.92%	5679	105	4
Paper (excluding Mills)	2504	42	0.017	0.61%	3266	55	11
Fabricated Metal Product	10158	89	0.009	0.73%	13989	123	10
Plastics and Rubber Products	4826	35	0.007	3.82%	25117	182	1
Logging and Wood Product	2254	12	0.006	-0.68%	1671	9	19
Chemical	21097	100	0.005	3.04%	78691	373	2
Transportation Equipment	12208	48	0.004	1.30%	21537	84	8
Printing and Related Support Activities	4378	14	0.003	0.46%	5347	18	13
Machinery	8723	26	0.003	1.73%	18526	56	5
Furniture and Related Product	3121	8	0.002	-1.59%	1543	4	23
Miscellaneous	11061	21	0.002	0.24%	12298	24	14
Electrical Equipment, Appliance, and Component	3216	5	0.002	2.63%	10080	16	3
Semiconductor and Other Electronic Component	21935	27	0.001	1.58%	43776	53	6
Apparel and Leather Product	4712	5	0.001	-1.61%	2309	3	24
Computer and Electronic Product (ex. Semiconductors)	69249	38	0.001	1.58%	137834	76	7
Total	214212	2139			415402	2835	
2050/2006 ratio					1.94	1.33	
Annual growth rate					1.52%	0.64%	

Table 6-2. *Industry sector GSP growth rate assumptions and frozen natural gas consumption with constant energy/GSP by sector. Industry sectors are ordered by energy consumption per GSP in 2006 (Masanet 2011).*

Description	2006 GSP	2006 Electricity Demand [GWh]	2006 GWh/ GSP	Projected GSP ann. growth	2050 Projected GSP	2050 Projected Electricity demand [GWh]	Rank by annual growth
Pulp, Paper, and Paperboard Mills	366	986	2.69	-0.27%	325	875	16
Petroleum and Coal Products	3110	7119	2.29	0.50%	3873	8866	12
Glass	984	695	0.71	-1.55%	495	350	22
Cement	2462	1624	0.66	1.92%	5679	3747	4
Plastics and Rubber Products	4826	2216	0.46	3.82%	25117	11532	1
Sugar and Confectionary Products; Fruit and Vegetable Processing	3201	1419	0.44	-0.76%	2286	1013	20
Textile Mills	562	224	0.40	-0.82%	392	156	21
Paper (excluding Mills)	2504	901	0.36	0.61%	3266	1175	11
Primary Metal	2561	899	0.35	-0.43%	2116	743	17
Food and Beverage	15812	5337	0.34	0.05%	16157	5453	15
Logging and Wood Product	2254	644	0.29	-0.68%	1671	477	19
Fabricated Metal Product	10158	2664	0.26	0.73%	13989	3669	10
Nonmetallic Mineral Product (ex. Glass and Cement)	5055	996	0.20	0.93%	7594	1496	9
Printing and Related Support Activities	4378	832	0.19	0.46%	5347	1016	13
Textile Product Mills	659	124	0.19	-0.61%	503	95	18
Chemical	21097	3907	0.19	3.04%	78691	14573	2
Transportation Equipment	12208	2231	0.18	1.30%	21537	3936	8
Machinery	8723	1387	0.16	1.73%	18526	2946	5
Electrical Equipment, Appliance, and Component	3216	487	0.15	2.63%	10080	1527	3
Furniture and Related Product	3121	432	0.14	-1.59%	1543	214	23
Semiconductor and Other Electronic Component	21935	2872	0.13	1.58%	43776	5732	6
Miscellaneous	11061	1012	0.09	0.24%	12298	1125	14
Apparel and Leather Product	4712	369	0.08	-1.61%	2309	181	24
Computer and Electronic Product (ex. Semiconductors)	69249	3702	0.05	1.58%	137834	7368	7
Total	214212	43079	0.20	1.52%	415402	78265	
2050/2006 ratio					1.94	1.82	
Annual growth rate					1.52%	1.37%	

Table 6-3. *Industry sector GSP growth rate assumptions and frozen end use electricity demand with constant energy/GSP by sector. Industry sectors are ordered by energy consumption per GSP in 2006 (Masanet 2011).*

6.6   Analytical Approach and Results

Our analytical approach is as follows. We track the following three categories of energy consumption: industry electricity consumption, oil and gas industry fuel consumption, and non-oil

and gas industry fuel consumption and use the growth rates as above for the frozen efficiency case. We adopt technical potential energy efficiency savings based on the PIER 2011 report on Long Term Energy Efficiency in California. This study projects about 28% savings from frozen efficiency in electricity in 2050 and about 44% in natural gas savings. Note that although this PIER study is limited to natural gas demand in the manufacturing sector only and thus represents only about 30% of overall fuel energy use, we still utilize this study as a benchmark for potential overall fuel savings.

We further assume that much higher levels of vehicle electrification and bio fuel production will sharply reduce the demand for in-state petroleum-based liquid fuels. Our scenarios assume a reduction in oil/gas extraction and refining activities by the same fraction that in-state fuel demand is displaced by vehicle electrification and bio fuel production, with no spillage from in-state gasoline production to out of state since we assume the world is sharply decarbonizing at the same time as California. In 2050 we project that 65% of the reference case oil and gas industry is replaced by electric vehicles and in-state or out of state bio-fuel supply consistent with the case of base case biomass supply availability. From the Biomass chapter, we assume that 2.8 billion gallons of gasoline-equivalent (Bgge) of bio fuels is produced in state for the base case. In the case of high biomass availability (7.5Bgge of biofuels produced in state), we project that 80% of the oil and gas industry is replaced.

From two biomass references (Tillman 2006, Masanet 2010) we assume the electricity generation requirements for a billion gge to be 13 TBtu currently improving to 9.4 TBtu per billion gge assuming 28% industry efficiency gains as above. For SWITCH electricity sector modeling, we include the electricity requirement for biofuels to comprehend the electricity impact of biorefineries. However, we do not account for additional fuel energy demand in other industry sectors in the production of biofuels and GHG emissions are accounted for by using a life-cycle analysis multiplier for biofuel emissions.

Finally after applying technical potential energy efficiency savings and reduction in oil and gas industry, we consider the electrification potential of remaining industry heat processes. Assuming 50% penetration of process heating starting in 2020, about 39% of industry fuel demand is projected to be electrified by 2050 in the base case with average savings of 50% in end use energy for electrified processes (EPRI 2010). This includes electrification of low and medium temperatures as well as utilization of heat pump technology but excludes high temperature thermal processing. In the high electrification case, about 53% of industry fuel demand is projected to be electrified by 2050 assuming a 75% electrification penetration of process heating starting in 2020.

In the base case this results in approximately the same electricity demand as the frozen case in 2050, or a rough doubling of demand in 2050 from present levels from 43,000 GWh to 84,000 GWh. Of this, about 33,000 GWh is due to increased demand from industry electrification. Overall fuel reduction of 73% is achieved compared to the frozen case (14.2 to 3.8 Bgge or equivalently, 1623TBtu to 429Btu). Industry energy projections are shown for the reference case, technical potential efficiency case, and base case (energy efficiency plus electrification of process heating) in Figures 6-2 to 6-4.

Industry electricity demand is shown in Figure 6-5. The reference case increases by 1.4% a year to 81,000 GWh in 2050. Technical potential efficiency achieves 28% savings to 58,000 GWh. Fuel switching and additional demand from biorefinery production starts to ramp up in 2020 and adds about 33,000 GWh by 2050. This results in overall industry demand in the base case of 92,000 GWh or 13% higher than the reference case.
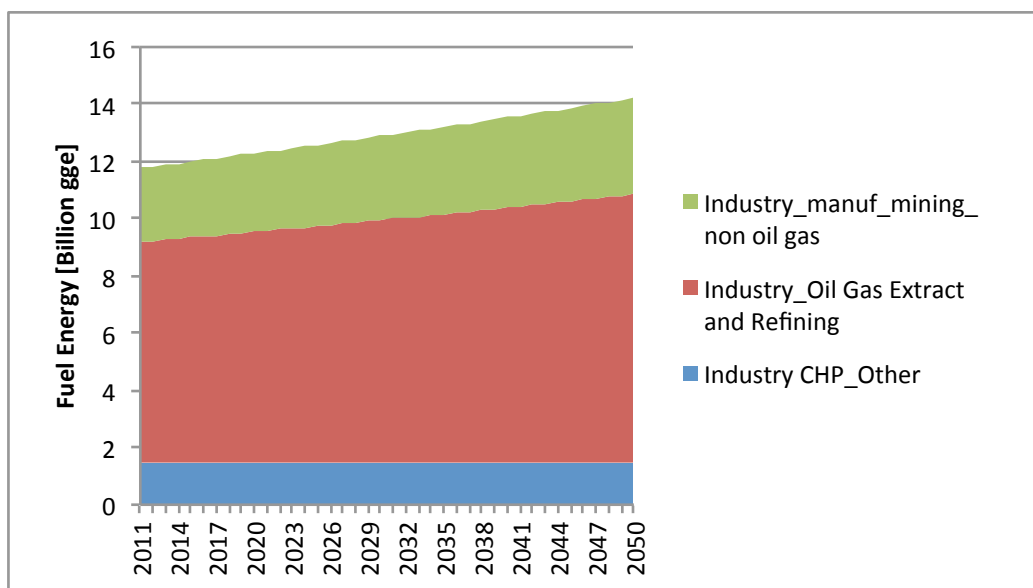
Figure 6-2. *Reference case (frozen energy efficiency) industry fuel demand split out into three sectors: non-oil and gas manufacturing and mining, oil and gas extraction and refining, and industry CHP and other.*
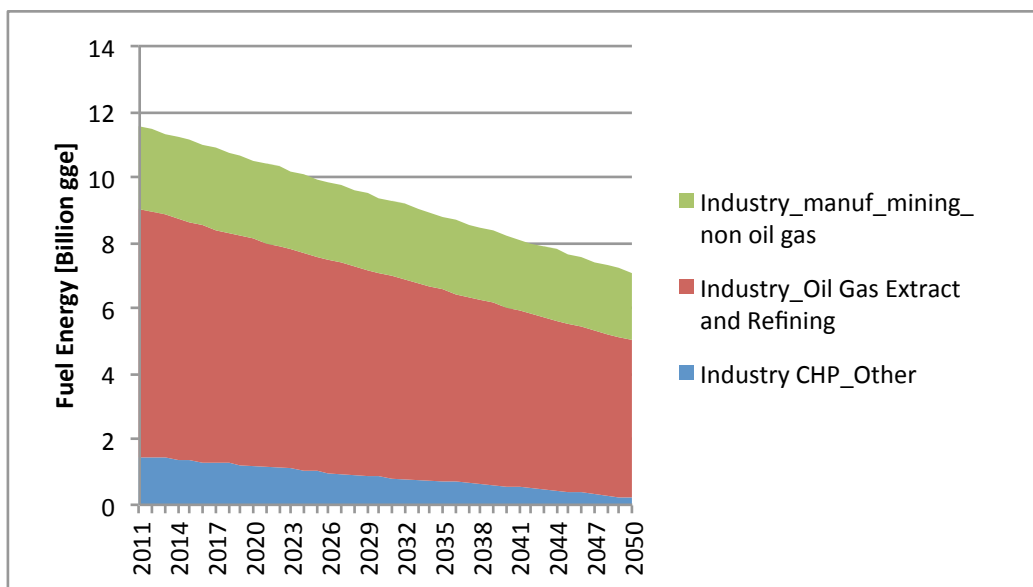
Figure 6-3. *Industry fuel demand with technical potential energy efficiency.*

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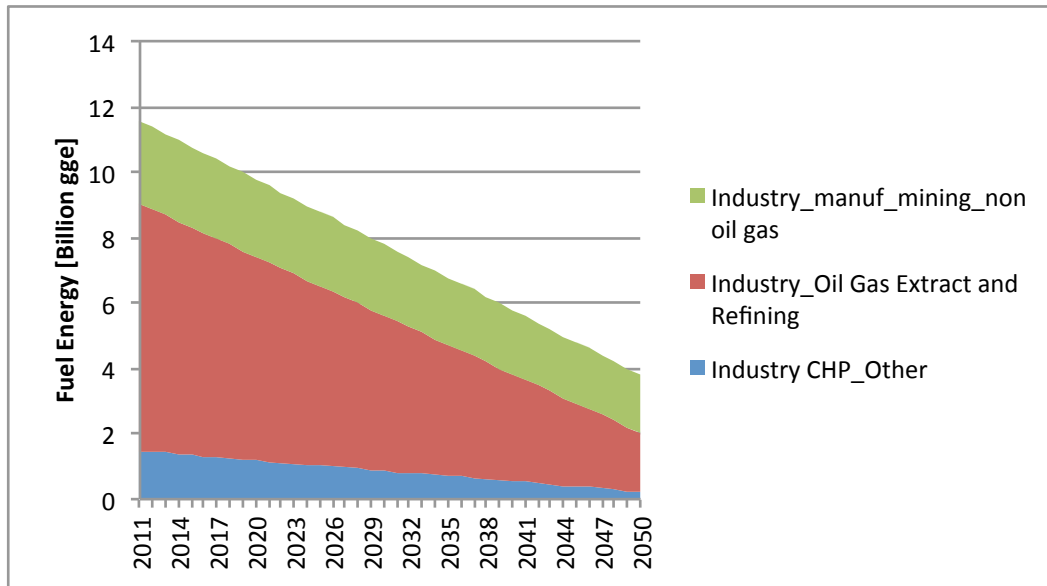
Figure 6-4. *Base case industry fuel demand (energy efficiency and electrification)*
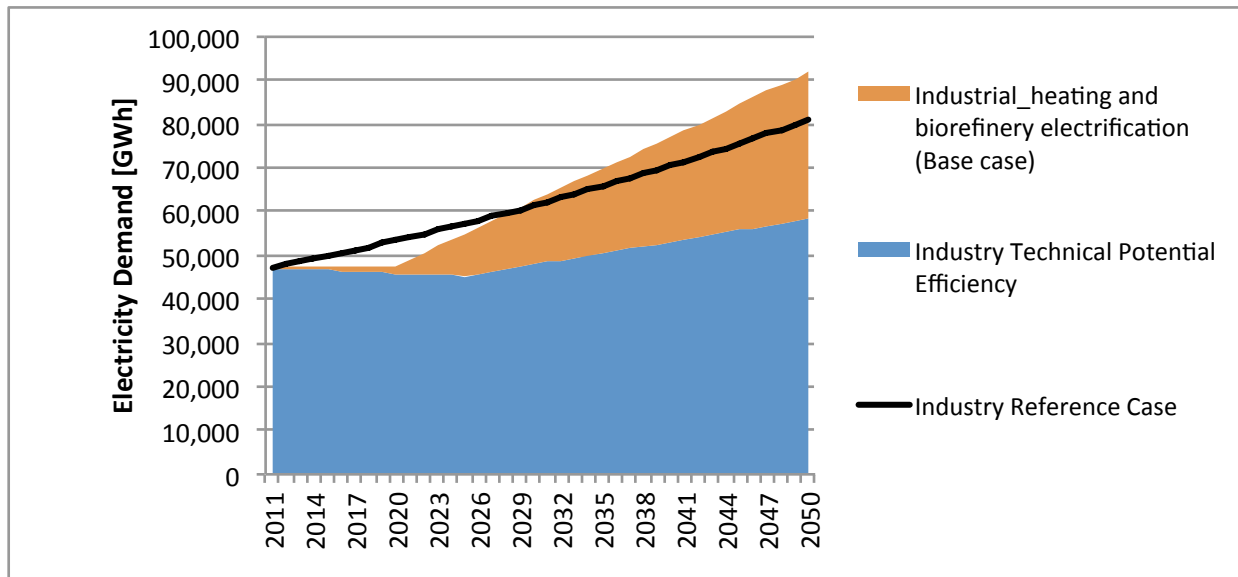
Figure 6-5. *Industry reference case electricity demand projection, technical potential efficiency, and technical potential efficiency with industry heating and biorefinery demand (base case).*

California industry electrification is utilized as a rough proxy for other regions in the West. We assume that industry electrification is delayed by 10 years for the rest of the WECC compared to California, starting in 2030, and take the incremental industry electrification demand increase in California in 2040 as a proxy for the rest of WECC in 2050 since it is assumed that California starts

10 years earlier in electrification. Based on relative regional growth rates differences in AEO2010, we take the Rocky Mountain and Pacific Northwest regional frozen growth rates to be higher at 1.6% and 1.8%, respectively. Industry growth rates in British Columbia and Alberta are based on 2007-2009 provincial utility projections. They average to be 2.6% annually to 2050 with a large contribution from the burgeoning mining, oil, and gas industry in Alberta. This may be an overly aggressive number for Canada in light of the recent recession of 2008-2009, but no further updated data projections were found.

Not treated under this framework is industry combined heat and power (CHP) and wastewater (see Section 8). We do not specifically treat CHP as a growing application area over time, since current CHP systems are largely natural gas and our general theme is to minimize fossil fuel use overall over time.

Industry growth is highly dependent on sectoral shifts and growth rates. It is possible that sectoral shifts could be significantly different from the projections taken here.   New industries or new sources of industrial demand could potentially emerge increasing energy demand. In particular, interactions between supply and demand in electricity/transportation/buildings/agriculture are not comprehended in this study. For example our industry projections are "static" in the sense that a dramatic build out of renewable energy or electric vehicle purchasing and infrastructure does not have any feedback to industrial activity.

As noted above, we also do not include integrated design improvements or novel materials or other technology breakthroughs.

7. OVERALL ELECTRICITY DEMAND

WECC regional electricity demands were disaggregated into four large sub-regions plus a small portion of Mexico for the analysis (Figure 7-1). The large sub-regions are: "CAN" (British Columbia and Alberta), "NW" (states in the Northwest), "CA" (California), and "RA" (Colorado, New Mexico, Arizona, and Southern Nevada). The Mexico region is relatively tiny portion of overall demand, and we assume baseline growth there throughout this work (1.5% annual growth in demand).
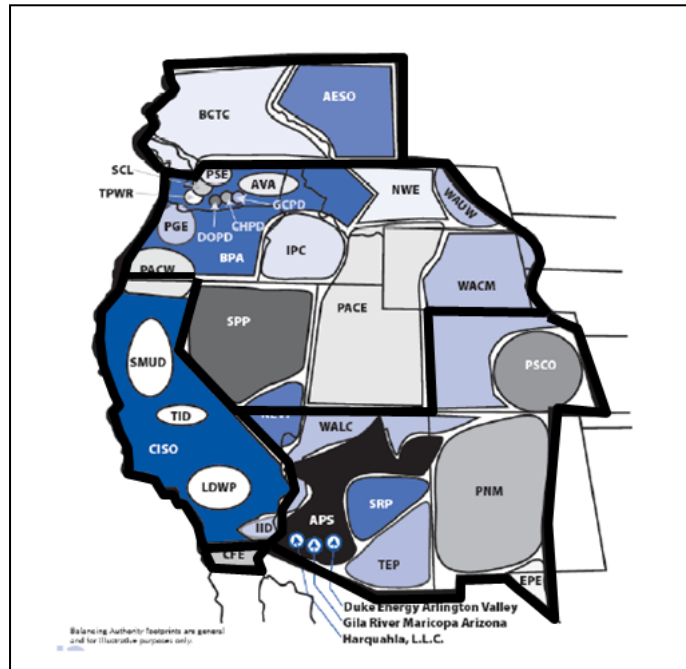
Figure 7-1. *Disaggregation of WECC Region into four sub-regions from top: "CAN" (Canada), "NW" (Northwest states), "CA" (California) and "RA" (Colorado, New Mexico, Arizona and S. Nevada.)*

We first describe baseline demand projections and then the technical potential efficiency and electrification scenarios.

Our general approach for modeling the rest of the WECC regions is to follow California demands as a proxy for the rest of the WECC (ROW). For the purposes of this study, we had access to a rich data set for California across the major sectors studied (buildings, industry, and transportation) and used this to generate "bottom up" electricity demands. However this type of data was not readily available for the ROW nor was it within the scope of the study to do similarly detailed ROW demand projections. As a simplification we assumed that the ROW would achieve same level of energy efficiency savings in all sectors, but that electrification of transport and building and industry heating is delayed by 10 years (Table 7-1). In other words if California EV sales start to surge in 2020, the ROW has the same sales adoption curves but pushed to 2030. Similarly, 2040 California incremental demands were used an approximate proxy for 2050 ROW in terms of degree of electrification and production of bio fuels. High level consistency checks were done in terms of

overall starting electrification by WECC region and climate zone impacts to the degree of building and industry electrification. For example we examined what percentage of space and water heating is already electrified in the ROW and to what degree demand would be increased or decreased due to climate differences.

Region	End use	Start	Full adoption
California	Space heating	2015	2025
California	Water heating	2015	2025
California	Boilers	2025	2035
ROW	Space heating	2025	2035
ROW	Water heating	2025	2035
ROW	Boilers	2035	2045

Table 7-1. *Adoption assumptions of baseline case electrified building heating for CA and ROW.*

This approach oversimplifies the building, industry, and transportation details in the ROW, but still extends the modeling framework for California's electricity system to a more realistic framework beyond what has been done in the past. A detailed accounting of each WECC region's electricity demand in similar detail to California was not within the scope of this work and is an area for more detailed study in the future.

7.1 WECC electricity demand projections

Reference case demand projections for U.S regions in the WECC are based on AEO projections and are extrapolated to 2050. Our convention is that reference case demand is "frozen efficiency" demand, which is consistent with many climate studies and also consistent with the treatment of energy efficiency in the building and industry sectors.

We use the AEO 2011 values as stating points and a synthesis of growth rates based on AEO and other sources for the frozen efficiency growth rates. We take the 2010 AEO growth rates for residential and commercial buildings since 2011 AEO growth rates are slightly lower based on future efficiency improvements in the residential sector (one round of energy efficiency standards are included).   Similarly in industry, we take the 2010 AEO growth rates since an increased penetration of CHP is assumed in the 2011 projections. Furthermore, industry is expected to have greater self- generated or "autonomous" efficiency savings than the residential and commercial sectors and thus frozen efficiency is taken to be about 0.8% higher than AEO estimates, e.g. from 0.6% in California to 1.4%. These growth rates are then applied to each sector's starting demand estimate in 2011 to generate annual demands to 2050.

Region	Residential	Commercial/Other	Industrial
CA	0.7%	1.4%	1.4%
NW	0.9%	1.6%	1.6%
RA	1.2%	2%	1.8%
CAN	1.6%	2.2%	2.6%

Table 7-2*. Reference Case electricity growth rate assumptions by sector for the four WECC regions.*

Canada estimates were taken from the two recent utility studies (British Columbia 2007 and Alberta 2009). Canada growth rates are largely driven by high demand projections in Alberta and for the oil and gas industry in particular, but these estimates may be on the high side. Canada was not hit as hard by the 2008-2009 recession and their growth rates are high compared to the U.S. regions.

Energy efficiency technical potential savings (TP) for are based on a PIER study on California energy efficiency savings that are described in the building and industry chapters (Masanet 2011). Agriculture/Other energy consumption savings are assumed to be same as Industry savings. Similar levels of technical potential savings are assumed for the rest of the major WECC regions.

After TP demand is computed, we add electrification demand from vehicle electrification and electrification of building heat and industrial heat. Transportation assumptions are discussed in Section 5 above. Building and industry electrification demand is based on Section 4 and 6, respectively. Figures 7-2 and 7-3 show California and the ROW electricity demand projection to 2050 and Figure 7-4 shows the total for the entire WECC. Curves shown include the reference frozen efficiency case, demand after technical potential energy efficiency savings and demand after TP savings and vehicle and heating electrification (base case).

Both California and the ROW building heating electrification scenario assume marginal penetration of heat pump based space heating and water heating with a ten year phase in starting in 2015 to full penetration by 2025 at the margin and for new construction for California and starting in 2025 for the ROW. Boiler system penetration starts in 2025 in California and 2035 in Canada (Table 7-1).

California is seen to represent about a third of overall WECC demand, and post electrification demand in 2050 is about 70% greater than electricity demand in 2011 and about 7% higher than the frozen efficiency case. For the WECC overall, demand is seen to remain flat to about 2025 and then sharply increase thereafter due to increased electrification demand from buildings, industry, and transportation. With the energy efficiency plus electrification scenario one sees that the overall demand is very close to the projected frozen efficiency demand or about 70% higher than 2011 demand.

Electricity demand for the case of high electrification of vehicles and industry heat in shown in Figures 7-5 to 7-7. For the case of California, electricity demand nearly doubles in 2050 from 2011 to 484,000 GWh, or about 22% higher than the frozen efficiency demand.
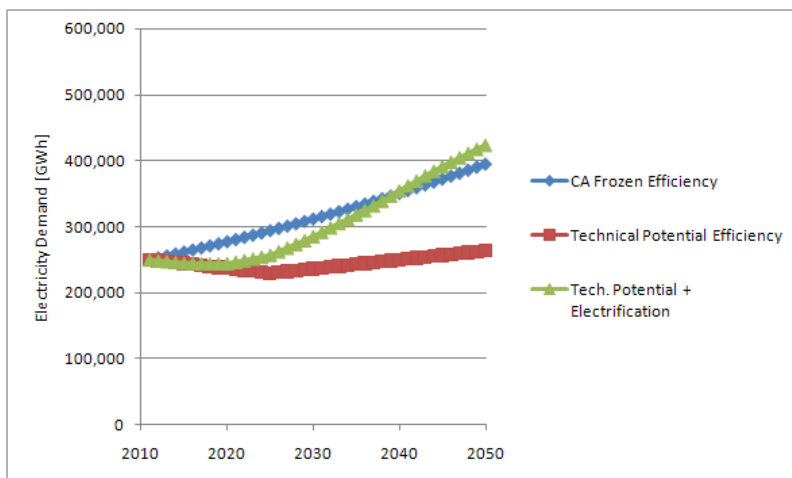
Figure 7-2. *California electricity demand showing frozen demand, demand after Technical potential efficiency improvements, and with electrification of building and industry heating (base case). Overall demand increases by about 70% from 2011.*
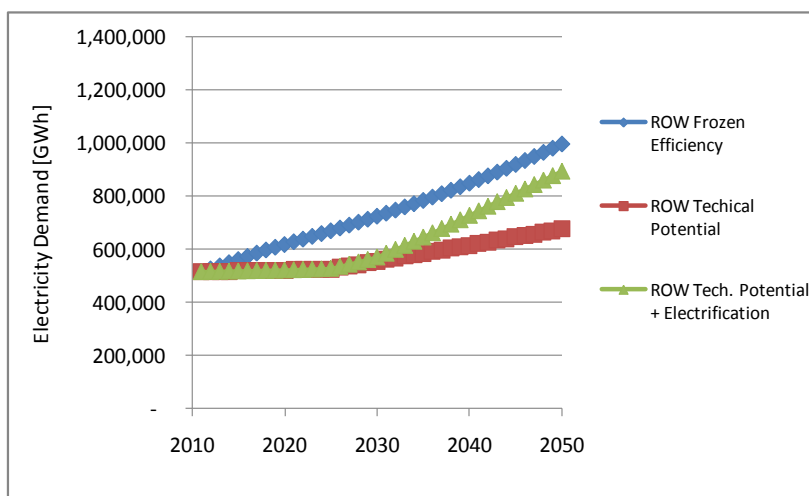
Figure 7-3. *Rest of WECC (ROW) electricity demand showing frozen demand, demand after Technical potential efficiency improvements, and with electrification of building and industry heating.*
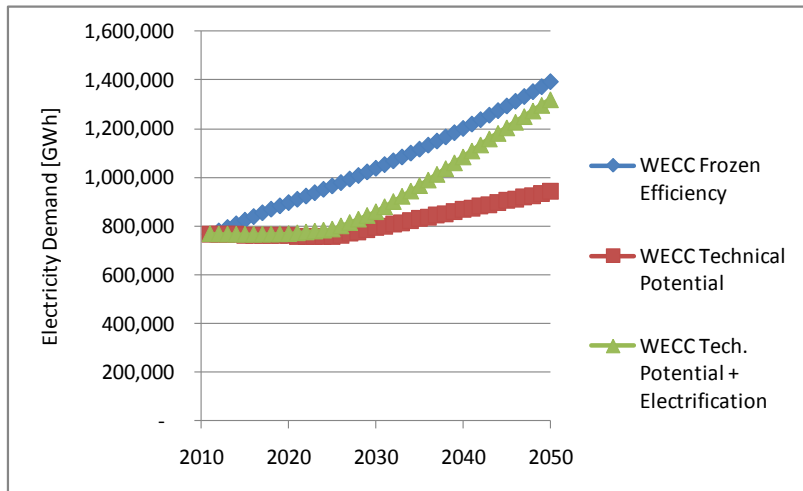
Figure 7-4. *Total WECC demand projection to 2050 showing frozen demand, demand after Technical potential efficiency improvements, and with electrification of building and industry heating.*
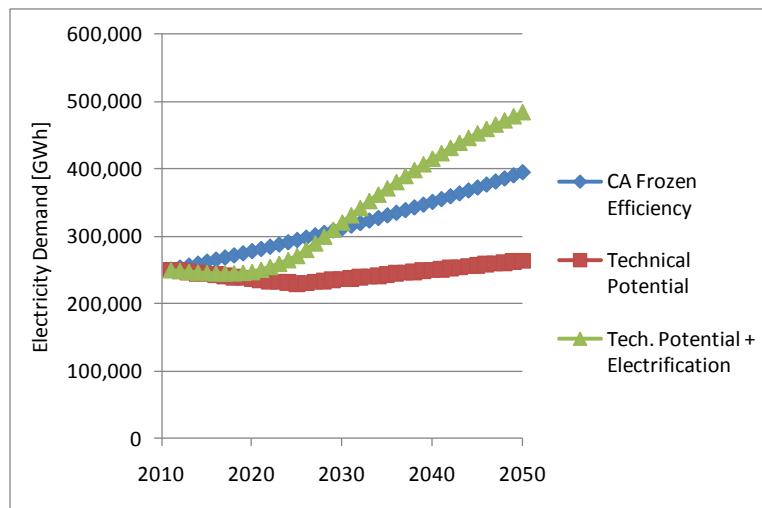
Figure 7-5. *California electricity demand showing frozen demand, demand after technical potential efficiency improvements, and with high electrification of transportation and industry eating. Overall demand is nearly doubled from 2011.*
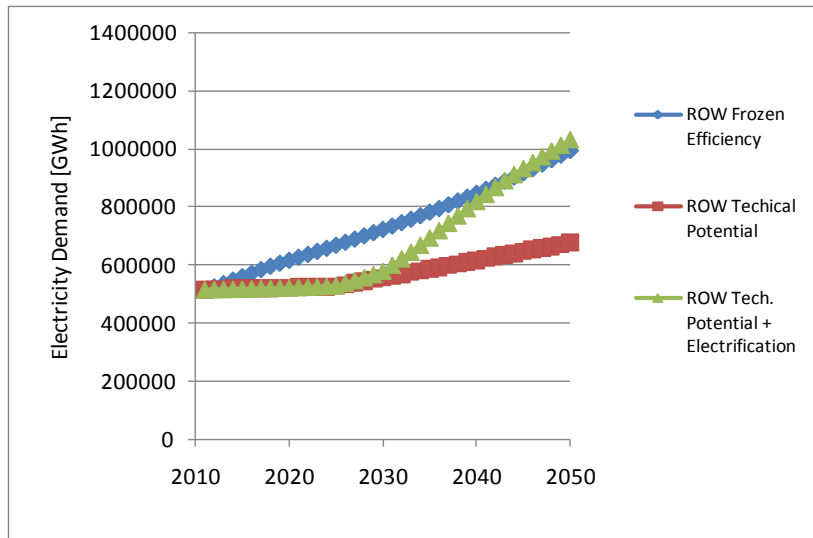
Figure 7-6. *Total WECC demand projection to 2050 showing frozen demand, demand after Technical potential efficiency improvements, and with high electrification of transportation and industry heating.*
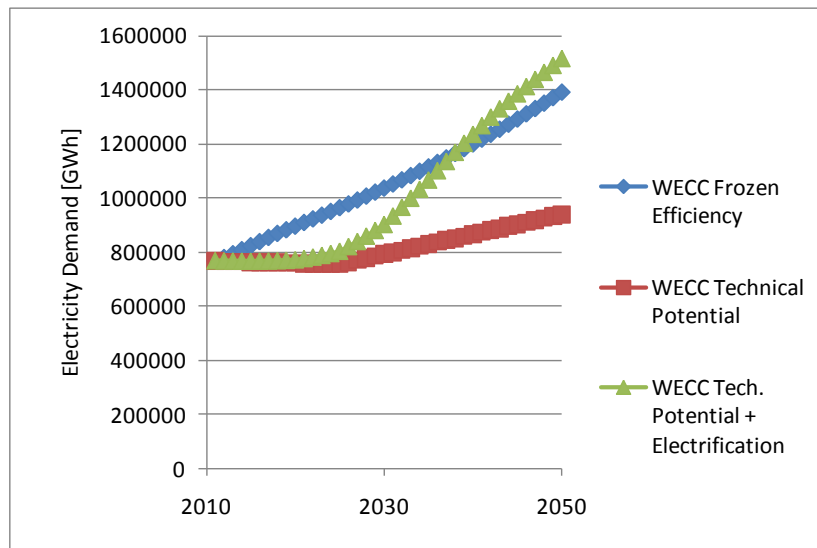
Figure 7-7. *Total WECC demand projection to 2050 showing frozen demand, demand after Technical potential efficiency improvements, and with high electrification of transportation and industry heating.*

8.   NON-ENERGY EMISSIONS – AGRICULTURE/FORESTRY, HIGH GWP, LANDFILLS

The following non-energy sectors were not treated in detail for this report: landfills (methane), the agricultural and forestry sector (methane and nitrous oxide), and high global warming potential (GWP) sources, primarily HFCs.   High GWP emissions in particular are projected to increase rapidly over the next decade (CARB2010) and by 2050, this area is projected to make up over one-sixth of total emissions in the reference case or 139 MMt CO2eq (Table 8-1).   Without a clearly defined path for reducing this sector to 80% below 1990 emissions (5.6 MMt target), this clearly is an important area for follow up work.

For non-energy emissions and agriculture/forestry we rely on earlier published reports from the CEC (Brown 2004, Choate 2005), ARB, EPA, and extrapolations to 2050. Here we briefly touch on key measures for emission reduction measures and related key challenges.   Economic viability for individual measures is a key challenge overall but cost per carbon saved is not within the scope of this study but is discussed in fuller detail in the two CEC reports.

8.1   High GWP Sources

A key challenge here is the high projected growth in high GWP sources.   ARB projects an extremely high annual growth rate in emissions (5.1%) to 2020 following historically high rates or growth from 2000 to 2008.   Extrapolating this growth with some moderation (annual growth dropping to 2.5% by 2050) implies that high GWP sources will account for 71 MMt CO2 in 2050.   Following historical trends, essentially 100% of these emissions will be from HFCs by 2050.

Semiconductor manufacturing high GWP process gas (SF6, NF3) abatement options exist to reduce emissions by up to 92%.   These include processing techniques to control and/or or reduce emissions through plasma etch abatement, remote cleaning, catalytic abatement, capture/recovery with membranes, and thermal destruction.

Electric power systems mitigation of SF6 can mitigate up to 100% of emissions with the leading option: leak reduction and recovery through leak detection, repair, and recycling.   The mitigation option assumes the implementation of SF6 Leak detection (e.g., infrared imaging systems), leak repair, and recycling activities.   CARB is considering a reduction of SF_6 emissions from gas insulated switchgear as a possible emission reduction measure within its Scoping Plan.

More challenging is HFC control and reductions. These represent about 75% of overall High GWP sources in the state and are projected to constitute 95% of high GWP emissions by 2020.   HFC emissions from refrigeration and air-conditioning in California are expected to grow steadily in the next decade as a result of phasing out ozone depleting substances used in refrigeration and air-conditioning and replacing them with HFCs. Choate 2005 projects technical potential of 25% reduction by 2020.   Key measures include improved system components, HFC-134a replacement, compressor system and secondary loop design optimization, leak reduction and repair, and recovery and recycling of refrigerant during equipment service and disposal.   We assume an overall 29% reduction in CO2-equivalent emissions from reference levels in 2020 (Choate 2005) and a 47% reduction in 2050 for high GWP sources based on an earlier reference from the EPA (EPA 2001).

Sector	2008 CARB Emissions [MMtCO2eq]	2050 Reference Case
Transport	175.0	313
Power	116.4	171
Industry	92.7	121
Commercial/residential	43.1	66
Total, Energy emissions	427	671
Landfills	6.7	16
High GWP	15.7	71
Agriculture/forestry	28.3	52
Total, Non-Energy emissions	50.6	139
Total, Energy and non-energy emissions	477.8	810

Table 8-1. *Reference case emissions by sector. Non-energy emissions represent 17% of emissions in 2050.*

8.2 Agriculture and forestry.

Agriculture and forestry emissions are projected to increase by about 1.3% per year and are projected to hold steady at about 6% of overall state emissions from 2011-2050. Long term emissions reduction strategy includes two key thrusts: reducing emissions levels from current sources, mainly livestock and fertilizer related emissions, and second, to pursue sequestration opportunities in forests and rangelands. Currently, livestock associated emissions (digestive processes and manure) are about 70% and fertilizers about 30% of agriculture non-energy emissions.

Key measures for manure management include the installation of lagoon covers or plug flow (non-mixed) digesters. Manure management systems can capture methane emissions and utilize them to produce heat or electricity. Plug flow digester can possibly be centralized with food processing wastes, and optimized multi-stage digestion system are possible. These measures are projected to reduce overall manure emissions by 65% in 2020.

In land management, Brown 2004 estimates up to 345-887MMt CO2 equivalent CO2 savings over a 20 year time window or approximately 17-44MMt per year at a cost of $5.50-$13.60/Mt CO2 from the afforestation of rangelands (Table 8-2). This would cover 2.7-12% of California land. This provides most cost effective carbon reduction practice with over two orders of magnitude greater impact than other management practices such as lengthening of forest management rotation or increasing forest riparian buffer width from protected streams. Conservation tillage has an estimated potential of 3.9MMt per year but at unknown cost in California. With the combination of

aggressive manure management and rangeland afforestation, the state appears to have a technical path to achieve an 80% reduction in overall agriculture/forestry emissions from 1990 level, although we do not consider the interaction of rangeland afforestation with the desire for maximal production of instate biomass for fuels. Without considering rangeland afforestation potential, overall savings of 48% is estimated for this sector in 2020 and 2050 relative to reference case levels, primarily from improved manure management.

Activity	Quantity of C—MMT CO2			Area available—million acres		
	20 years	40 years	80 years	20 years	40 years	80 years
FOREST MANAGEMENT						
Lengthen rotation						
</= $13.60 (discounted C)	3.47	--	--	0.31	--	--
</= $ 13.60 (undiscounted C)	2.16	--	--	0.3	--	--
Increase riparian buffer-width						
</=$13.60	3.91 (permanent)				0.044	
GRAZING LANDS						
Afforestation						
</=$13.60	887	3,256	5,639	12.03	17.79	20.76
</= $5.50	345	3,017	5,504	2.72	14.83	19.03
</=$2.70	33	1,610	4,569	0.2	5.68	13.34

Table 8-2. *Carbon savings from forest management practices as a function of price per ton of CO2 (Brown 2004).*

8.3   Landfills

Methane is the greatest non-CO2 GHG emissions contributor in CA. Methane is emitted during the production, transportation, and refining operations of petroleum and natural gas systems, and is a by-product of anaerobic decomposition that occurs in landfills, wastewater treatment systems and manure management systems. Methane from petroleum and natural gas system is treated in the industry section and is sharply curtailed with petroleum industry replacement.

Methane emissions from landfills are assumed to grow at 2% per year to 2050. The technical potential reduction from landfills is estimated to be 85% savings in 2020 (Choate 2005). Methane emissions from landfills can be reduced by capturing the CH4 before it is emitted into the atmosphere. This can be done by installing direct gas use projects or electricity projects with backup flare systems to recover and use CH4. In this work we assume that landfill emissions can be sharply reduced from the greater utilization of biomass sources that are directed to supply biomass for biofuels as well as technical potential improvements in methane recovery options.   We assume 85% savings from reference case levels for both 2020 and 2050.

9. SUPPLY SECTORS – BIOMASS SUPPLY

9.1 Biomass Supply

In this section we describe the in-state biomass availability and biofuel supply assumptions for the various scenarios. We do not discuss biomass to biofuel conversion technology or biomass production and land issues since that has been treated in great detail in other references.

The research team made the following simplifications in the disposition of biomass supply. First, our intention was to direct all biomass supply to either biofuels or bio-power (electric power). A more careful optimization would consider policy environments (tax credits, incentives, etc.), cost evolution assumptions of bio-fuels versus biomass-fired power plants, as well as other details (biomass type, geography, conversion efficiencies, etc) to determine the relative weighting for liquid biofuels versus electricity and heating. However, this simple approach is considered to be within the scope of the overall study and illustrative of two extremes of biomass utilization.

We further note that it is difficult to fully electrify the transport sector while there are many available technologies for producing clean electricity and that the transportation sector demand analysis indicates a still sizable remaining demand for liquid fuels (almost 10 billion gallons gasoline for light duty passenger vehicles and trucks alone in 2050 for the base case). Thus in all cases but the two biomass CCS cases, all in-state biomass is directed to biofuel production with none made available for electricity. In the biomass CCS cases only, we utilize a supply curve based biomass supply for SWITCH. Existing supply curve data out to 2020-2030 is employed, as the team was not comfortable with extrapolating existing supply curves to 2050. Not all available biomass supply is utilized by SWITCH, and the residual supply was made available to produce biofuels.

Biomass supply curves for California are taken primarily from the following sources: POLYSIS/University of Tennessee based supply curves to 2030 for agriculture residues and energy crops (University of Tennessee 2007), and 2020 municipal solid waste (MSW) estimates from UC-Davis (Parker 2011). Biomass supply curves were generally inclusive of costs up to <$100/dry ton. Technical potential biomass supply estimates were taken from the CEF study (CCST 2011) for California. Extending these results to generate longer term supply curves and projecting supply curves technical potential biomass supply is an area for follow up work.

We choose to limit imported biofuels to no more than 25% of total supply for all cases except one case which allows high imported biofuels. This is consistent with moving to a more independent, energy secure energy system by lessening imported energy from abroad. The constraint is also consistent with the Governor's Executive Order S-06-06 (2006), which calls for the state to produce at least 20% of its biofuels by 2010, 40% by 2020, and 75% by 2050. As seen in Figure 6-1, over 1/3 of crude oil supplied to California refineries is foreign crude oil in 2005, up from less than 10% in 1990. It is certainly possible that a large quantity of biofuel could be imported to California in the future and this could significantly contribute to meeting long term carbon targets if they are sufficiently low carbon biofuels. However, the research team did not want to rely on this scenario in order to quantify energy system requirements with a more constrained biofuel supply and to build maximal self-sufficiency.

Our base case takes 35 Million dry tons available for biofuel in 2050 as a synthesis of POLYSIS 2007 and UC-Davis (Parker 2010). For the Biomass CCS scenarios, we take a biomass supply of 23M dry tons i.e. the biomass supply for which there are supply curves available to 2030 for agricultural residues and 2020 for MSW (35 million dry ton overall supply less 7 million dry tons of yard waste, food waste and construction demolition and less 5 million dry tons of energy crops). The remaining 12 million dry tons are made available to biofuels in this scenario. In the biomass CCS high biomass supply case, we take a higher estimate for overall instate biomass supply (94 Mdt) and again make 23Mdt available for electricity and the rest for biofuels. In all other case, biomass supply is directed exclusively to biofuel production.

High estimates for biomass supply range from 40-110M dry tons for California (CCST 2011). The CEF takes 94 million dry tones for an overall supply of 7.5 billion gallons gasoline equivalent. We adopt this as the high biomass supply case in our scenarios, consistent with the technical potential framework that is used in the building and industry sectors. While the research team was not comfortable with extrapolating the supply curves to 2050 in either the quantity of biomass or price for a given quantity of biomass, it is certainly possible that technology breakthroughs could elevate the quantity and/or make the cost of individual biomass feedstocks more affordable.

The high biomass scenario results from higher growth in herbaceous and forests residues, improved technical yield recovery[15] (from 40% to 64%), substantial investment in additional energy crops (woody and herbaceous), and utilization of abandoned agricultural and non-productive forest lands. Possible scenarios based on earlier PIER reports and the higher biomass case are shown in Figure 9-1.
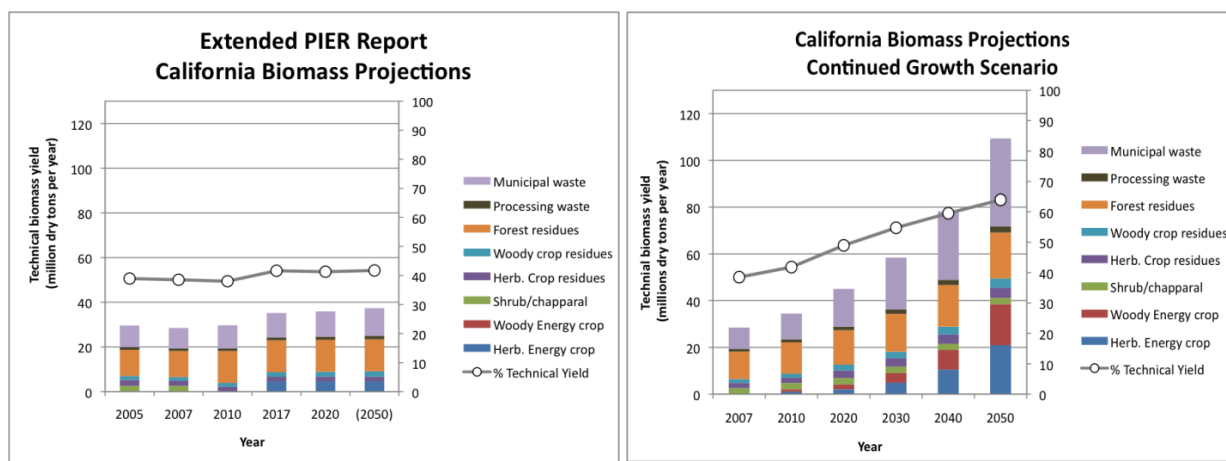
Figure 9-1. *Biomass supply projections for California (from Heather Youngs).*

A possible ramp up of biomass supply and biofuel production is shown in figures 9-2 and 9-3 based on scenarios for high ethanol production from Heather Youngs of the Energy Biosciences Institute

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[15] Technical yield is defined as the product of technical yield percentage and gross biomass in dry tons.

in Berkeley. This scenario is certainly not the only pathway toward achieving 2050 production targets nor is it a unique mix of biofuel products, but does illustrate the extremely rapid ramp up and scale of production that is required to meet the targets. The large ramp up starting in 2030 is to allow sufficient time for several cycles of learning from bench scale development to development pilots to small scale production to large scale production, as well as time to development the land areas required to meet biomass production at these levels.

We assume cellulosic ethanol has a production yield of 70 gallons per dry ton today and increases to 112 gallons per dry ton in 2050 (80 gallons gasoline equivalent per dry ton) which is the current technical limit. We also assume that the overall biofuel CO_2-eq impact on a life-cycle basis is 70% of gasoline LCA emissions currently based on the present mix of biofuels in the state, evolving to 20% of gasoline LCA impact in 2050 (EPA 2009A) as the in-state and out of state mix of biofuels become dominated by low carbon biofuels. Biomass supply assumptions and lifecycle emissions associated with liquid biofuels are a key hinge factor for future state emissions (e.g. indirect CO_2 impacts of energy crops). Sensitivity to biofuel production and life-cycle assumptions will be quantified in future work.
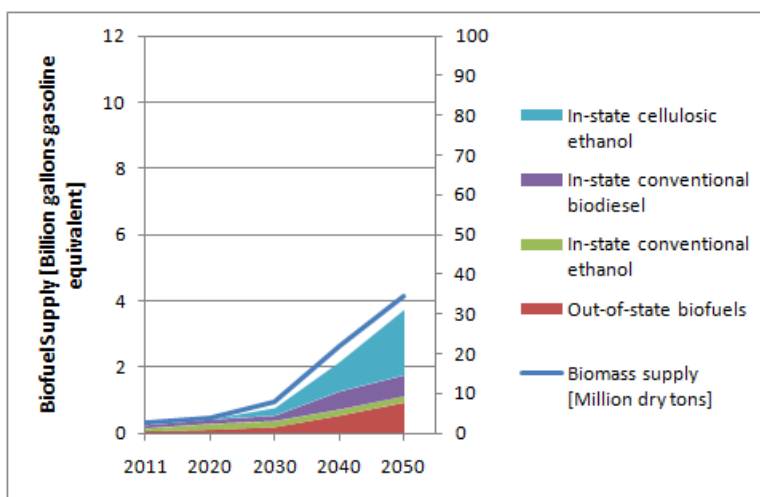
Figure 9-2. *Biofuel supply in base case with imports constrained to 25% of overall supply. Biomass supply reaches 35 million dry tons in 2050 or total biofuel supply of 2.8Bgge.*
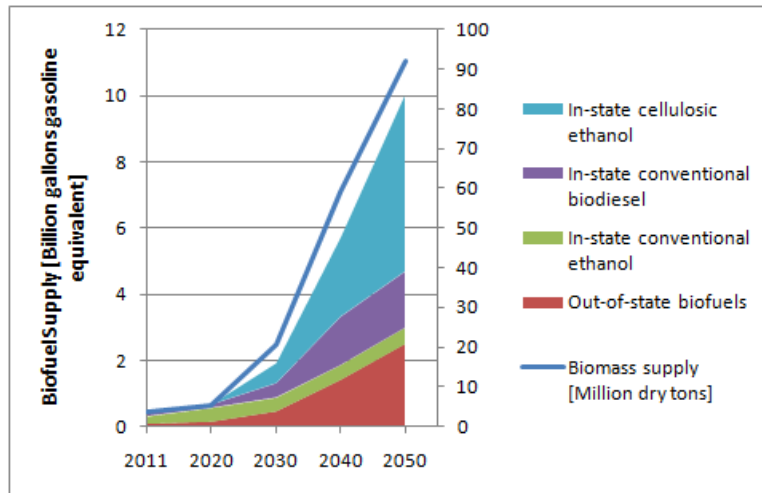
Figure 9-3. *Biofuel supply in high in-state biofuel case with imports constrained to 25% of overall supply. Biomass supply reaches 94 million dry tons in 2050, or total biofuel supply of 10Bgge.*

10.   ELECTRICITY SUPPLY MODELING RESULTS

10.1   Introduction

SWITCH (Figure 10-1) is a capacity-expansion and dispatch model of the electric power sector. In this study, SWITCH is used to model the entire geographic extent of the Western Electricity Coordinating Council (WECC). The model is a mixed-integer linear program whose objective function is to minimize the cost of delivering electricity from present day until 2050 with generation, transmission, and storage subject to policy, carbon emission, resource availability, and generator output constraints. SWITCH is well suited to project the optimal deployment of a low-carbon WECC power system as it models a large geographic region in detail at a high temporal resolution. It was created at the University of California, Berkeley by Dr. Matthias Fripp (Fripp 2008; Fripp 2012). The version of SWITCH used in this study is maintained and developed by Ph.D. students James Nelson, Ana Mileva, and Josiah Johnston in Professor Daniel Kammen's Renewable and Appropriate Energy Laboratory.
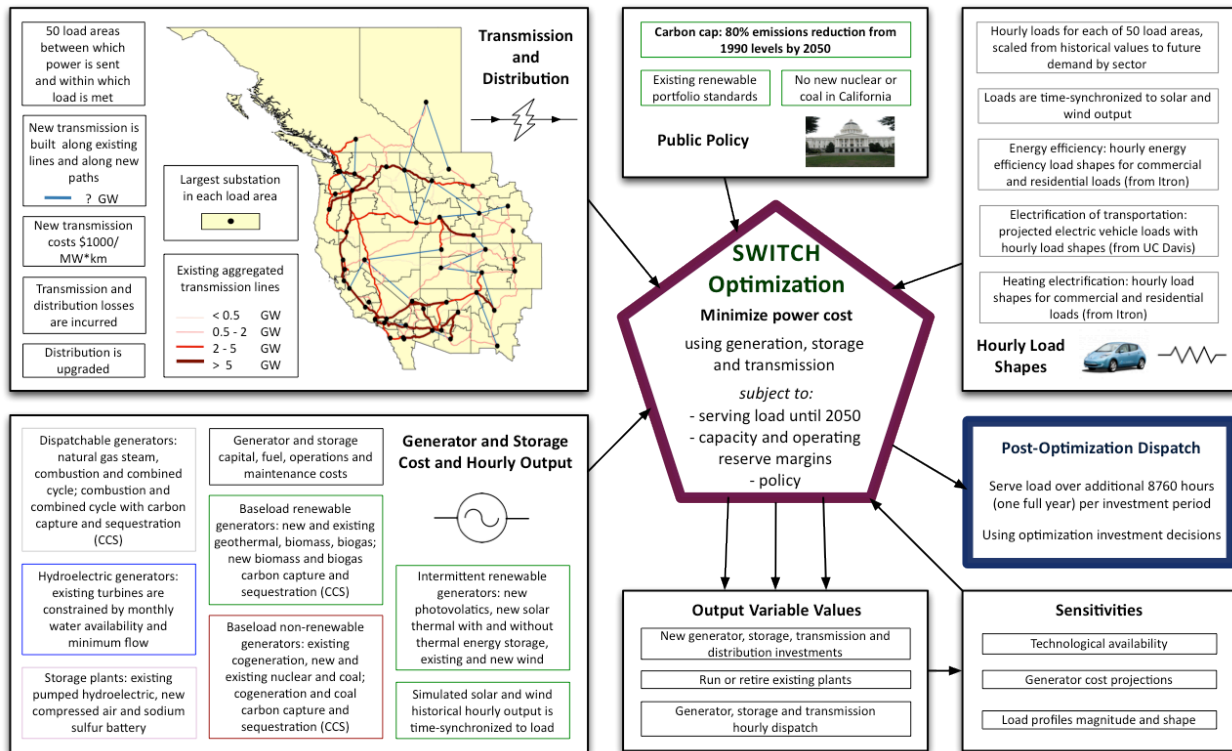
Figure 10-1: *Diagram of data inputs, optimization, and outputs of the SWITCH model.*

It is likely that future low-carbon electricity systems will rely on renewable generation sources such as solar and wind. However, the intermittency of solar and wind generation poses challenges for power grids in which a large fraction of power originates from these sources. Many capacity expansion models of the electricity grid encounter difficulties with the spatially and temporally

complex nature of intermittent resources relative to conventional generators. To address these issues, SWITCH uses time-synchronized hourly load and renewable generation profiles in a capacity expansion model. SWITCH determines the contribution of baseload, dispatchable and intermittent generation options alongside storage and transmission capacity on a least-cost basis while ensuring that projected electricity load is met reliably subject to policy constraints. The model concurrently optimizes investment in and dispatch of power system infrastructure, an approach that allows for proper valuation of intermittent renewable capacity at varying levels of intermittent penetration.

While this study focuses on the state of California, it is important to consider regions outside California with respect to future electricity production. California currently makes up approximately one third of electricity load in the Western North American electric power interconnect, the area coordinated by the Western Electricity Coordinating Council (WECC). WECC is depicted in Figure 10-2. California currently imports hydroelectric power from the Pacific Northwest, and coal and nuclear power from the Desert Southwest. These imports may be subject to change in the 2050 timeframe, and it is therefore essential to explicitly model all of WECC in an integrated framework in order to account for interactions between California and the rest of the region.

In the version of SWITCH used in this study, WECC is divided into 50 'load areas,' within which power is generated and stored, and between which power is transmitted. Twelve of these 50 load areas are in California. Load areas represent nodes of electricity demand within WECC. In addition, load areas correspond to parts of the existing electric power system within which there is significant transmission and distribution infrastructure, but between which limited long-range, high-voltage transmission currently exists. Consequently, load areas are regions between which new transmission may be needed.
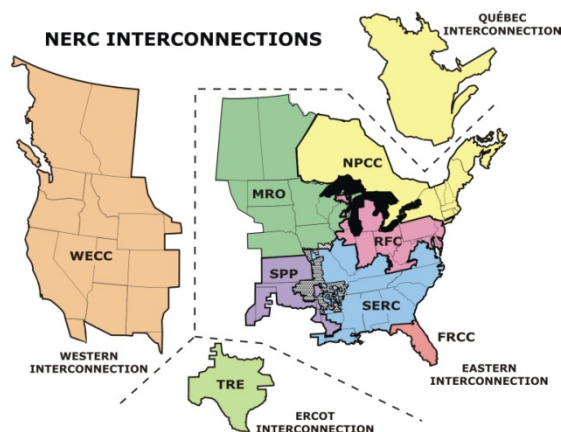
Figure 10-2: *North American Electricity Reliability Corporation (NERC) interconnections. Dashed lines represent divisions between wide area synchronous electric grids. The version of the SWITCH model used in this study encompasses the entirety of WECC, but does not include trading with other interconnects. Little power is currently transmitted between WECC and the other two North American interconnects. Figure reproduced from* http://www.nerc.com/page.php?cid=1%7C9%7C119.

In the model, four 'investment periods,' each ten years in length, span the time between the present day and 2050. The first of these investment periods represents 2015-2025 and the last represents 2045-2055. At the start of each investment period, SWITCH chooses which generation, storage and transmission projects to build. All investment periods are optimized simultaneously, so projects installation decisions in earlier investment periods affect decisions made in later periods, and vice

versa. SWITCH is well suited to investigate a gradually decreasing cap on carbon emissions as near-term investments will be consistent with long-term emissions constraints.

SWITCH operates existing power system infrastructure and can build new generation, transmission and storage capacity in order to meet load cost-effectively. Each optimization is given the option to build over 7500 generation projects, 200 storage projects, and 100 transmission projects in each investment period. Installable generation and storage projects are shown in Figure 10-3 below. Existing power plants are operated individually and non-hydroelectric plants can be retired before the end of their projected operational lifetime. If not retired earlier for economic reasons, non-hydroelectric plants must retire at the end of their operation lifetime. Hydroelectric and pumped hydroelectric generators run indefinitely into the future, incurring concomitant operation and maintenance costs.

SWITCH makes power system investment and dispatch decisions simultaneously, thereby evaluating the present and future value of infrastructure investments within the context of their hourly value to the electric power system. Within each investment period modeled in this study, the available infrastructure (as determined by the investment decisions) is dispatched over 144 'study hours.' Study hours represent conditions from the middle of each investment period, so subsequent results will show the 2045-2055 investment period as '2050' for simplicity. Study hours are chosen such that the peak and median load days from each month are input to the optimization. Each of these days includes six hours, evenly spaced throughout the day at four hour intervals (12 months per investment period * 2 days per month * 6 hours per day = 144 hours per investment period). For each study hour and each load area, the model is constrained to meet projected hourly system load as well as a capacity reserve margin of 15% above load. Unlike operating reserves (spinning and quickstart reserves), the capacity reserve margin includes contribution from plants that are not required to have quickstart capability or to be online.

In all SWITCH scenarios presented here, operating reserve requirements similar to rules evaluated in the Western Wind and Solar Integration Study (GE Energy 2010) are included. The study found that holding an amount of spinning reserves equal to 3% of load and 5% of intermittent generation was generally conservative and resulted in sufficient amount of reserves over large balancing areas. SWITCH employs similar balancing areas: California, Pacific Northwest, Rocky Mountains, Southwest, Western Canada, Baja Mexico. In each of the six SWITCH balancing areas, in each study hour, the model is constrained to keep an amount of both spinning and non-spinning reserve greater than or equal to 3% of load and 5% of intermittent renewable generation. Dispatchable natural gas, hydroelectric, and storage plants can provide operating reserves in the version of SWITCH used in this study. Operating reserves from demand-side flexibility have not yet been included.

Four different categories of generators are operated: baseload, intermittent, dispatchable and hydroelectric. Baseload generators (coal, biomass, biogas, geothermal, nuclear, cogenerators) are operated at the same level of output in every study hour. Intermittent generators (solar, wind) produce power corresponding to their hourly capacity factor in each study hour. Dispatchable generators (non-cogeneration natural gas and hydroelectric) can vary their level of energy output as a function of installed capacity and, for hydroelectric, the water availability conditions in each

study hour. Dispatchable generators can also adjust how much capacity to keep in both spinning and non-spinning reserve within each study hour. Hydroelectric generators can vary hourly output subject to average historic generation and minimum flow requirements. Storage projects (compressed air, pumped hydroelectric, sodium sulfur battery) are similar to dispatchable generators, but are also subject to an energy balancing constraint within each day.

Generator capital cost projections are among the most important drivers of capacity expansion models because of their large contribution to the total cost of energy. Default generator and storage project overnight capital cost assumptions are shown in Figure 10-3. In SWITCH, learning and economies of scale from generator installation are modeled as an exponentially decreasing function over time. No generation technology is modeled as having increasing capital costs over time, though nuclear capital costs are assumed to stay constant. In the default cost assumptions, the capital cost of photovoltaics decreases fastest among technologies, at a rate of 4-5% per year, reflecting their large cost-reduction potential, a history of large cost decrease, and projected large-scale installation worldwide. Overnight capital costs are derived primarily from the California Energy Commission Cost of Generation Model (California Energy Commission 2010) and the United States Energy Information Agency Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010).

Fuel costs are another large cost in capacity expansion models. Natural gas and coal fuel costs are extrapolated to 2050 from the Reference Case of the United States Energy Information Agency's National Energy Modeling System (NEMS) Annual Energy Outlook (Annual Energy Outlook 2011). In California, natural gas and coal costs reach \$9.27/MMBtu and \$2.18/MMBtu in \$2007 by 2050, respectively. Biomass fuel costs are included through a supply curve in each load area, as shown in Appendix 5, Table 1. Uranium cost projections are taken from California Energy Commission's 2007 Cost of Generation Model (Klein 2007) and reach \$2.16/ MMBtu in \$2007 by 2050.

Existing power transfer capacity between load areas is included, and new transmission capacity can be added at a cost of \$1000/MW-km. New capacity is added along existing rights-of-way where possible, and incurs an additional \$500/MW-km for creating new rights of way. Transmission between load areas is represented using a transportation network model and transmission lines are constrained to not exceed thermal limits. It should be noted that the current version of SWITCH does not include load flow transmission constraints, i.e. it does not strictly obey Ohm's and Kirchhoff's laws nor does it include stability limits for very long AC transmission lines. Similar transportation network models have been used successfully to plan power system capacity expansion, but future work will investigate SWITCH investment plans under more stringent load flow constraints.

10.2 Base Case Scenario Description

In this study, the SWITCH model is used to demonstrate a range of scenarios in which the electric power sector of Western North America (WECC) reaches deep carbon emission reduction targets by 2050. In the Base Case scenario, the optimal SWITCH power system is constrained to meet a target of 80% below 1990 CO_2 emission levels across all of WECC. This 80% reduction is consistent

with economy-wide California emission targets, requiring the electric power sector to contribute to emission reductions in the same proportion as the rest of the economy.

Overnight Captial Cost Average ($2007/W_p)

Overnight Cost Declination Rate (%/yr)	Technology
-0.56	Battery Storage
-1.44	Biogas
-1.94	Biogas CCS
-1.48	Biomass IGCC
-1.70	Biomass IGCC CCS
-1.48	Coal IGCC
-1.70	Coal IGCC CCS
-1.19	Coal Steam Turbine
-1.37	Coal Steam Turbine CCS
-1.35	Gas Combined Cycle
-1.82	Gas Combined Cycle CCS
-1.44	Gas Combustion Turbine
-1.94	Gas Combustion Turbine CCS
-0.12	Gas Compressed Air Energy Storage
-1.00	Geothermal
-0.00	Nuclear
-0.89	Solar CSP Parabolic Trough 6h Storage
-0.89	Solar CSP Parabolic Trough No Storage
-3.73	Solar PV Central Station 1-Axis Tracking
-4.57	Solar PV Commercial
-4.85	Solar PV Residential
-0.05	Wind
-1.30	Wind Offshore

Legend: ■ 2020 ■ 2030 ■ 2040 ■ 2050

Figure 10-3: *Average generator and storage overnight capital costs in each investment period. Plants not eligible for construction in the 2020 investment period are excluded from this chart. The costs shown do not include expenses related to project development such as interest during construction, connection costs to the grid and upgrades to the local grid, though these costs are included in the optimization. In addition, costs incurred after construction such as fuel costs as well as operation and maintenance costs are input to each optimization but are not included here.*

In the Base Case scenario as well as all other scenarios investigated here, existing state-based renewable portfolio standard (RPS) targets are met in future years. In the model, RPS targets are met with renewable power produced locally or delivered via transmission lines – 'unbundling' of power produced from renewable energy credit is not allowed. In future years for which RPS targets are not explicitly specified, we assume a target equal to that in the latest year for which a target was specified. Renewable tax credits are not considered as their existence far into the future is uncertain. The California Solar Initiative is not currently modeled by SWITCH, but will be included in the future.

Generator capital costs in the Base Case scenario are as discussed in the previous section, but sensitivities of the optimal power system to variations in these costs are explored below.

Load profiles used in this study are derived from the Federal Energy Regulatory Commission's (FERC) Form 714 hourly load data reported by load-serving entities for the historical year 2006 (Federal Energy Regulatory Commission 2006). These profiles are allocated to the 50 SWITCH load

areas and then scaled according to load projections (Section 7). Hourly profiles for energy efficiency (Section 4), vehicle electrification (Appendix 5, Figure 1), and heating electrification (Section 4) are
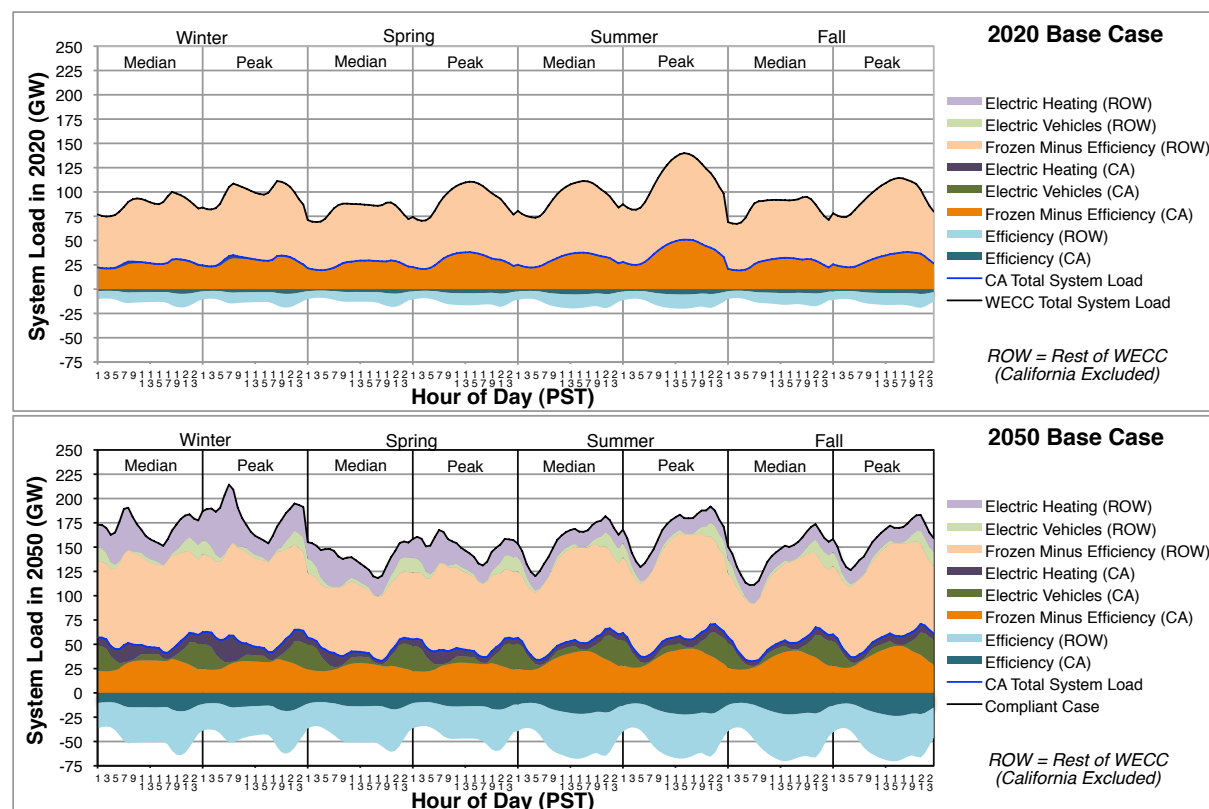
Figure 10-4*: Hourly load profiles by load type for the Base Case load profile in 2020 and 2050. For each season, the day with the peak load hour and the day with the median load are shown. 24 hours of data per day are plotted. Vertical gray lines divide distinct days. 'Frozen Minus Efficiency' represents the load profile after efficiency measures have been taken. 'Efficiency' is depicted here as negative load, representing the difference between the frozen efficiency load profile and the same load profile including energy efficiency reductions.*

then added to the base load profile to obtain a full year of hourly load forecasts (8760 hours) for all 50 load areas. The Base Case scenario load profile includes substantial vehicle and heating electrification as well as aggressive energy efficiency measures. As a result, the WECC-wide 2050 load shape is transformed: instead of a load profile with a late-afternoon summer peak as in present day, in 2050, load peaks on winter nights as shown in Figure 10-4. California remains a summer-peaking system, but with the peak shifted to the late evening by electric vehicle load. The version of SWITCH presented here treats load as fixed and therefore does not allow load participation in the balancing of electricity supply and demand.

10.3 Base Case Scenario Results

The electric power system in the Base Case scenario changes dramatically between present day and 2050 (Figure 10-5) in order to adapt to changes in load profile resulting from efficiency, vehicle

electrification, and heating electrification, as well as an ever more stringent constraint on carbon emissions.

As simulated in SWITCH, the present day (2011) electric power system is dominated by coal, natural gas and hydroelectric generation, representing 29%, 24% and 31% of WECC-wide generation respectively. Nuclear, geothermal and wind make up the balance of generation. California relies heavily on imports, comprising 42% of its total power (Table 10-1). This level of imported power is high relative to recent reports that estimate imports to be roughly 1/3 of all California power (CEC 2007B). As SWITCH does not honor current power purchase agreements between generators and utilities, this is likely due to unrealistically quick reorganization of power transfers within WECC. Projections into the future, especially in the 2050 timeframe, will have less of this discrepancy, as power contracts are generally on much shorter timescales. However, it should be noted that even without the explicit simulation of power purchase agreements, SWITCH qualitatively simulates present day power system dynamics correctly, with California importing a large fraction of its load from coal and nuclear power in the Southwest and hydroelectric power in the Pacific Northwest.

Wind, geothermal and biogas generation are added by 2020 to meet RPS demand for renewable power (Figure 10-5A and 10-5C), as well as to decrease the carbon intensity of power generation back to 1990 levels by 2020 as required by the carbon cap constraint. As is the case in the present day WECC power system, hydroelectric generation dominates in the Pacific Northwest and is transmitted to California (Figure 10-6). Coal generation dominates in the Rocky Mountains and Desert Southwest, with much coal electricity shipped to California. In the 2020 Base Case scenario, California relies heavily on out-of-state power imports (Table 10-1): in-state generation accounts for only 17% of WECC-wide generation while California accounts for 32% of WECC-wide load in 2020. Solar generation does not appear in the optimal 2020 generation portfolio as its high costs preclude installation. Future inclusion of the California Solar Initiative policy in the SWITCH model will bring solar into the generation mix before 2020 and likely reduce imports from out of state.

Investment Period	CA Average Net Transmission Imports [GW]	CA Average In-State Generation [GW]	CA Average Load [GW]	CA Import Percentage [%]
2011	12.7	17.8	28.3	42%
2020	13.7	16.2	27.9	46%
2030	16.1	17.9	31.8	47%
2040	14.6	27.6	39.5	35%
2050	18.7	31.9	46.8	37%

Table 10-1: *Average California power imports by investment period in the Base Case scenario. The 'Import Percentage' denotes the fraction of total power available to meet load that comes from imports, i.e. the net transmission imports into California divided by the sum of net transmission imports into California and total generator output within California. The difference between the total power available to meet load and the system load represents losses within the system from transmission, storage, distribution and spilling power.*
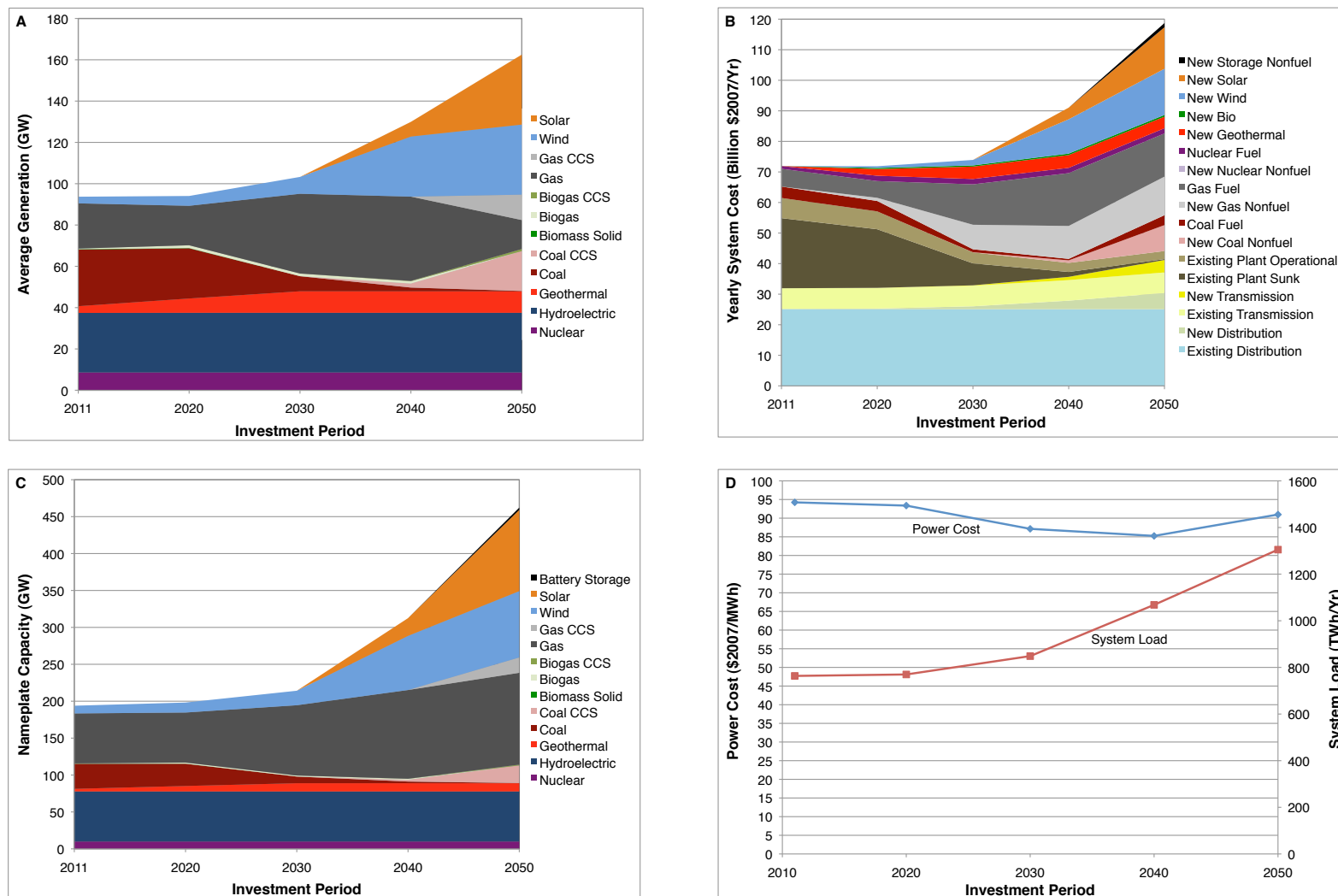
Figure 10-5: *Base Case scenario results as a function of investment period for all of WECC. All but the first investment period are modeled as ten year long periods starting five years before and ending five years after the year on the x-axis. The first investment period of 2011 represents a SWITCH simulation of the existing electric power system in which only investment in natural gas peaking turbines is allowed. (A) Average generation over each investment period (B) Yearly system cost breakdown (C) Installed nameplate generation and battery storage capacity. Pumped hydroelectric and compressed air storage projects are included with 'Hydroelectric' and 'Gas' respectively. (D) Power cost normalized to load, and total yearly system load.*
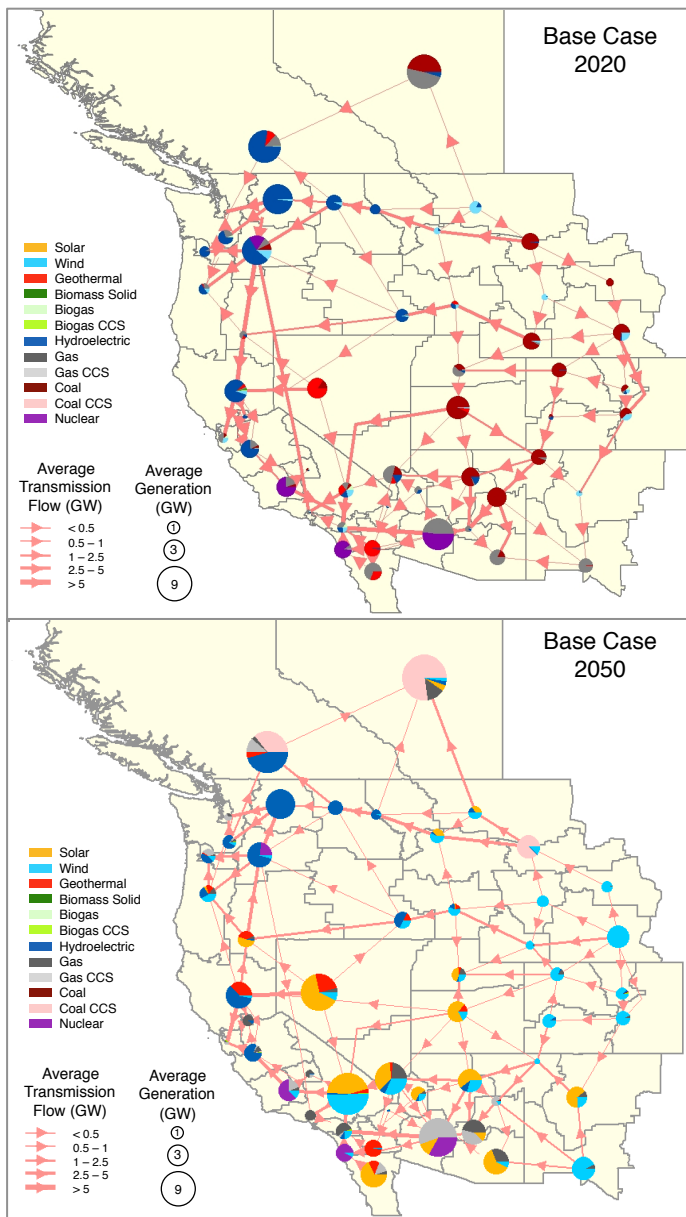
Figure 10-6: *Average generation by fuel within each SWITCH load area, and average transmission flow between load areas in 2020 (Top) and 2050 (Bottom). The size of each pie represents the amount of generation in the load area in which the pie resides. Transmission lines are modeled along existing transmission paths, but are depicted here as straight lines for clarity. Note that these maps portray* <u>*average*</u> *generation and transmission over the course of an investment period, and as such dispatch of the electric power system may vary greatly from these maps in some hours.*
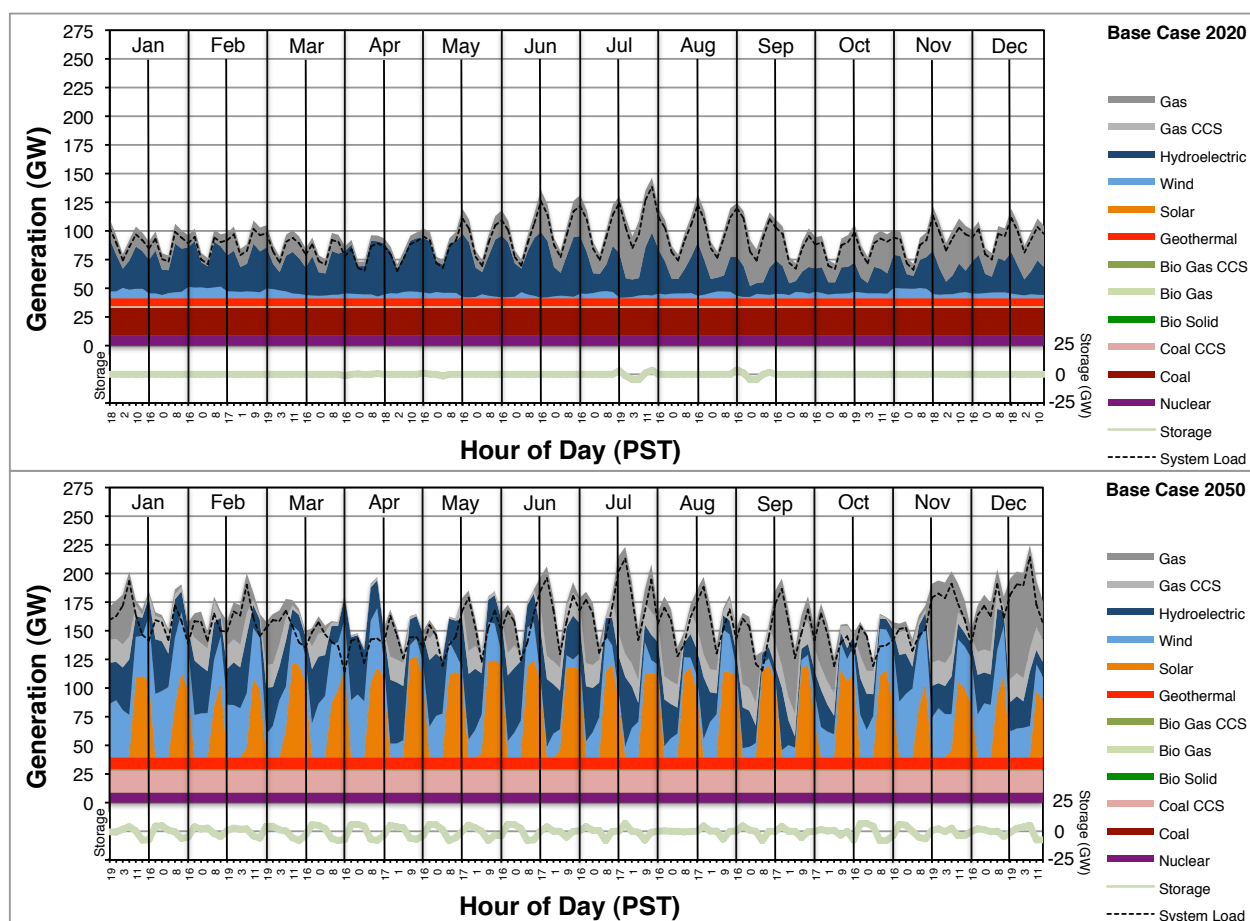
Figure 10-7: *Hourly dispatch of the Base Case scenario optimal electric power system for all of WECC in 2020 (Top) and 2050 (Bottom). Each plot depicts six hours per day, two days per month, and twelve months per year. Each vertical line divides different simulated days. Optimizations are offset eight hours from Pacific Standard Time (PST), and consequently start at between hour 16 and hour 19 of each day. The system load line does not equal the total generation in each hour due to energy storage and losses in transmission and distribution. The hourly dispatch of storage is shown in light green below each generation plot, with negative values corresponding to energy storage and positive values corresponding to energy release.*

As the power system evolves past 2020, the combination of increasing RPS targets and a more stringent carbon cap forces coal-fired generation out of the generation mix, in favor of primarily natural gas, but also wind and geothermal. By 2050, all existing coal-fired generation has been retired. Much of it is replaced by new coal plants equipped with carbon capture and sequestration (CCS), sited predominantly in Montana and Canada,where coal fuel costs are low. About 10% of power comes from natural gas CCS, which is generally cycled diurnally (Figure 10-7), providing power during the night in order to charge electric vehicles and heat buildings. Heavy investment in new gas-fired generation starts in 2030 and continues through 2050, but this investment is largely to replace aging existing gas-fired generation. Investment in photovoltaics increases rapidly as capital costs fall to ~\$1/W$_p$ by 2050, whereas the installation of wind is more gradual over time in large part due to its slower projected cost declination rate (Figure 10-3). Distributed rooftop photovoltaics are not installed in GW scale as their lower capacity factor and similar costs relative

to central station photovoltaics make their deployment unattractive. SWITCH does not capture the set of market dynamics, policies, and individual decisions that affect adoption of distributed photovoltaics, so is likely underestimating deployment. No concentrating solar power (also known as 'solar thermal') is installed in the Base Case scenario or any other scenario investigated in this study due to high costs relative to central station photovoltaics. CSP with thermal storage was not considered in the model and should be included in future research.

Central-station solar is installed in the Desert Southwest, whereas wind power is installed primarily along the backbone of the Rocky Mountains as well as in California (Figure 10-6). Solar and wind generation are geographically separated from load, necessitating 14,000 GW-km of new long-distance, high-voltage transmission by 2050 throughout Western North America (Figure 10-9). The largest new transmission lines bring solar power from Nevada into California, increase power transfer capability between Canada and the United States, and ship Rocky Mountain wind power westward. In 2050, California is a net electricity importer (Table 10-1), generating 20% of WECC-wide power and consuming 33% of WECC-wide load.

Solar and wind generation complement each other temporally. A combination of gas, gas CCS, hydroelectric and storage are used to follow the load net generation from intermittent renewables and baseload resources. In addition to the existing WECC-wide 5 GW of existing pumped hydroelectric storage, 0.5 GW of compressed air energy storage and 3 GW of battery storage are installed by 2050 to provide spinning reserves (Figure 10-8) and to temporally shift solar generation to periods of high demand from electric vehicle loads and electric heating (Figure 10-7). Solar power is consumed in California and the Desert Southwest in the daytime, as well as sent out toward load centers in the Rocky Mountains and the Pacific Northwest. Wind power from the Rocky Mountains is consumed locally and also transmitted west at times of high demand. Throughout WECC, 42% of electricity originates from intermittent sources (solar and wind) in the Base Case in 2050. Despite the installation of storage, SWITCH finds the lowest cost power system spills 1.6% of total generated power. Should storage costs decrease faster than projected in this study, or if demand-response programs are deployed at scale, more of this power could be utilized instead of spilled.

The large-scale generation from intermittent renewables found in this scenario necessitates backup generation in case of weather forecasting errors. Spinning reserves, which are able to respond on the ten-minute timescale to compensate for unexpected variation in generation and load, are provided primarily by hydroelectric and storage technologies (Figure 10-8). Less gas-fired generation provides spinning reserves in 2050 because sub-optimal part-load efficiency penalties – and resultant carbon emission – make their use undesirable under a strong carbon constraint. In addition, the large balancing areas employed in this study enable the use of spinning reserves from hydroelectric and pumped hydroelectric generators over large geographic regions. "Quickstart" (also called non-spinning reserve) capacity, which is able respond to contingencies on the thirty-minute timescale, is provided almost exclusively from natural gas and natural gas CCS generation.
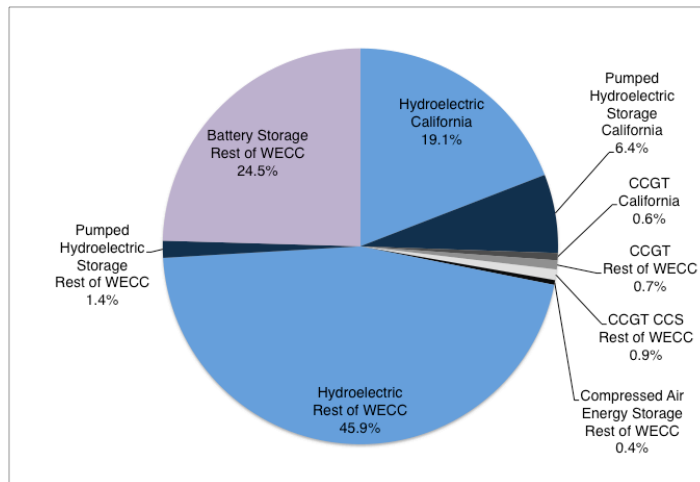
Figure 10-8. *Average spinning reserves in the Base Case scenario in 2050, broken down by technology and geographic area.*
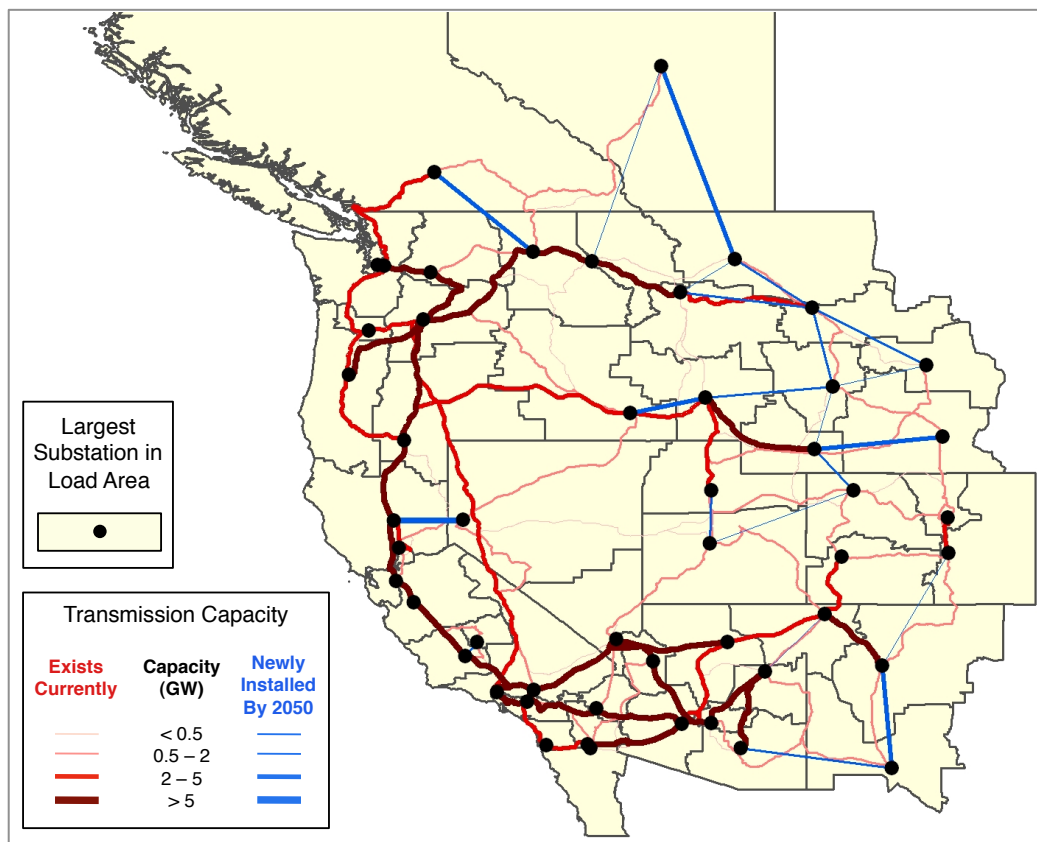
Figure 10-9*: Existing and new transmission capacity between load areas in 2050 for the Base Case scenario. New transmission is built along existing transmission corridors when possible, but is depicted here with straight lines for clarity. Note the addition of large amounts of new transmission capacity to bring predominantly solar power from Northern Nevada into the Central Valley and San Francisco Bay Area regions of Northern California. Also, note the new transmission additions in the upper right of this map that bring Rocky Mountain wind west.*

Our Base Case scenario results project that the cost of electricity per unit of energy stays relatively constant between present day and 2050, at between $85/MWh and $95/MWh (in $2007), as shown

102

in Figure 10-5D. These findings are in contrast to some reports (e.g. AEF 2009) which project that the cost of electricity will increase steadily over time as carbon emission reductions are enforced. In the SWITCH results presented here, the added cost of decarbonizing the electric power system is largely offset by decreasing generator costs over time as well as structural reorganization of the grid to meet load cost-effectively. This result is robust within the SWITCH modeling framework, as similar cost conclusions can be drawn for the other eight carbon-constrained sensitivity cases we investigate subsequently. A larger exploration of the cost parameter space, as well as an in-depth comparison between the differences in cost assumptions between SWITCH and other models, is necessary to provide added confidence in the cost conclusions presented here.

10.4   Base Case Dispatch Verification

The decisions made by each SWITCH optimization use a limited number of sampled hours over which to dispatch the electric power system. While the model has state-of-the art hourly resolution for a large-scale capacity expansion model, each investment period in this study optimizes on 144 sampled hours – much less than a full year of load and intermittent renewable data. To verify that the model has in fact designed a power system that can function over a full year of hourly load and intermittent renewable output data, a dispatch verification check is included. In this check, performed after each optimization, investment decisions are held fixed and new, unseen hourly data are tested in batches of one week at a time. The results from each scenario simulated in this study are therefore checked using 8760 hours of data for each of the four future investment periods, making a total of 4 investment periods x 8760 hours per investment period = 35,040 hours simulated. If there is not sufficient generation capacity to meet demand and reserve constraints, more peaking gas combustion turbine capacity is added to the system to compensate. As is the case in the version of SWITCH used for this study, this dispatch check does not include generator ramping constraints, security constraints, and load flow transmission constraints.

In all but one single hour of the 35,040 total, the base case scenario is able to meet demand and operating reserve constraints. The single hour that fails necessitates installation of 155 MW of extra peaking capacity – an insignificant amount of capacity and concomitant cost with respect to the scale of the WECC power system. The success of this check adds validity to SWITCH's method of sampling median and peak load study hours as well as enforcing a 15% capacity reserve margin in each study hour of the investment optimization.

10.5   Generator and Cost Sensitivity Scenarios

The projected capital cost and availability of certain types of power generation is a source of substantial uncertainty, especially in the 2050 timeframe. We model these uncertainties using a scenario-based approach by varying the projected capital cost of generation technologies within a feasible range, or by adding/removing generation technologies from the array of technologies from which SWITCH can choose. The matrix of scenarios investigated in this study is found in Table 10-2.

Among the generation options investigated here, carbon capture and sequestration (CCS), nuclear, and solar capital cost projections are believed to be the most uncertain.

Photovoltaic capital cost projections vary widely, so we explore the sensitivity of the optimal power system to both higher and lower PV costs than in the Base Case scenario. In the Inexpensive Solar & Wind scenario, the costs of all intermittent generators – solar thermal, solar photovoltaic, onshore wind and offshore wind – decrease more rapidly than in the Base Case in order to demonstrate a power system dominated by intermittent renewable generation. The Expensive Photovoltaics scenario explores a future in which photovoltaics do not meet cost reduction targets in order to demonstrate a power system that does not rely extensively on inexpensive photovoltaic generation.

In the Inexpensive Nuclear and Inexpensive CCS scenarios, respectively, nuclear and CCS costs are reduced relative to the Base Case scenario in order to demonstrate power systems with large amounts of low-carbon baseload power.

In addition to the capital cost of generation, the viability of large-scale carbon capture and sequestration (CCS) deployment is also uncertain in the 2050 timeframe. CCS has been proven at demonstration scale only, and recent reports of carbon leakage bring into question the long-term viability of this technology. To model a possible future without large-scale CCS deployment, we include the No CCS scenario, in which all CCS options have been removed from the fleet of generators available to SWITCH. We also include the No CCS Or New Nuclear scenario, in which both CCS and new nuclear generations are not available

We also model a Biomass Solid CCS scenario, in which the electric power system is able to sequester carbon via biomass integrated gasification combined cycle (IGCC) CCS generators. For this scenario, the portion of solid biomass available at less than or equal to $100 per dry ton is unavailable as a feedstock for transportation fuel. We explore a scenario in which it is made available to the electricity sector instead. In the Biomass Solid CCS scenario, the electric power sector is constrained to be carbon-neutral (i.e. to have 100% emissions reductions from 1990), which would allow the electric power sector to offset additional emissions from the transportation sector.

Scenario	Load Profile	California Load in 2050 [TWh/yr]	Total WECC load in 2050 [TWh/yr]	Carbon Cap [% reduction from 1990 Emission Levels]	Extra Capital Cost Declination Relative to Base Case [%/yr]	Generators Included or Excluded
Frozen, No Carbon Cap	Frozen Efficiency	395	1368	N/A	N/A	Biomass Solid CCS Excluded
Frozen Efficiency	Frozen Efficiency	395	1368	80%	N/A	Biomass Solid CCS Excluded
Base Case	Base Case	424	1310	80%	N/A	Biomass Solid CCS Excluded
Inexpensive Nuclear	Base Case	424	1310	80%	Nuclear: -2%/yr	Biomass Solid CCS Excluded
Inexpensive CCS	Base Case	424	1310	80%	CCS: -1.5%/yr	Biomass Solid CCS Excluded
No CCS Or New Nuclear	Base Case	424	1310	80%	N/A	All CCS and New Nuclear Excluded
No CCS	Base Case	424	1310	80%	N/A	All CCS Excluded
Inexpensive Solar And Wind	Base Case	424	1310	80%	Solar & Wind: -1%/yr	Biomass Solid CCS Excluded
Expensive Photovoltaics	Base Case	424	1310	80%	Photovoltaics: +1.5%/yr	Biomass Solid CCS Excluded
Biomass Solid CCS	Base Case	424	1310	100%	N/A	Biomass Solid CCS Included
Extra Electrification	Extra Electrification	484	1478	80%	N/A	Biomass Solid CCS Excluded

Table 10-2. *Electricity scenarios considered in this study.*

We model one additional scenario, the Frozen, No Carbon Cap scenario, in order to assess the cost difference between a low-carbon and a high-carbon electric power system. The Frozen, No Carbon Cap scenario differs from the Base Case scenario in that carbon emissions from the electric power sector are unconstrained over time. The Frozen Efficiency load profile (discussed below) is used to

represent a load profile similar to that which exists today. Current RPS targets are enforced in this scenario.

Figures 10-10 through 10-13 below show key metrics for each of the scenarios studied and are followed by descriptions of scenario-specific results.
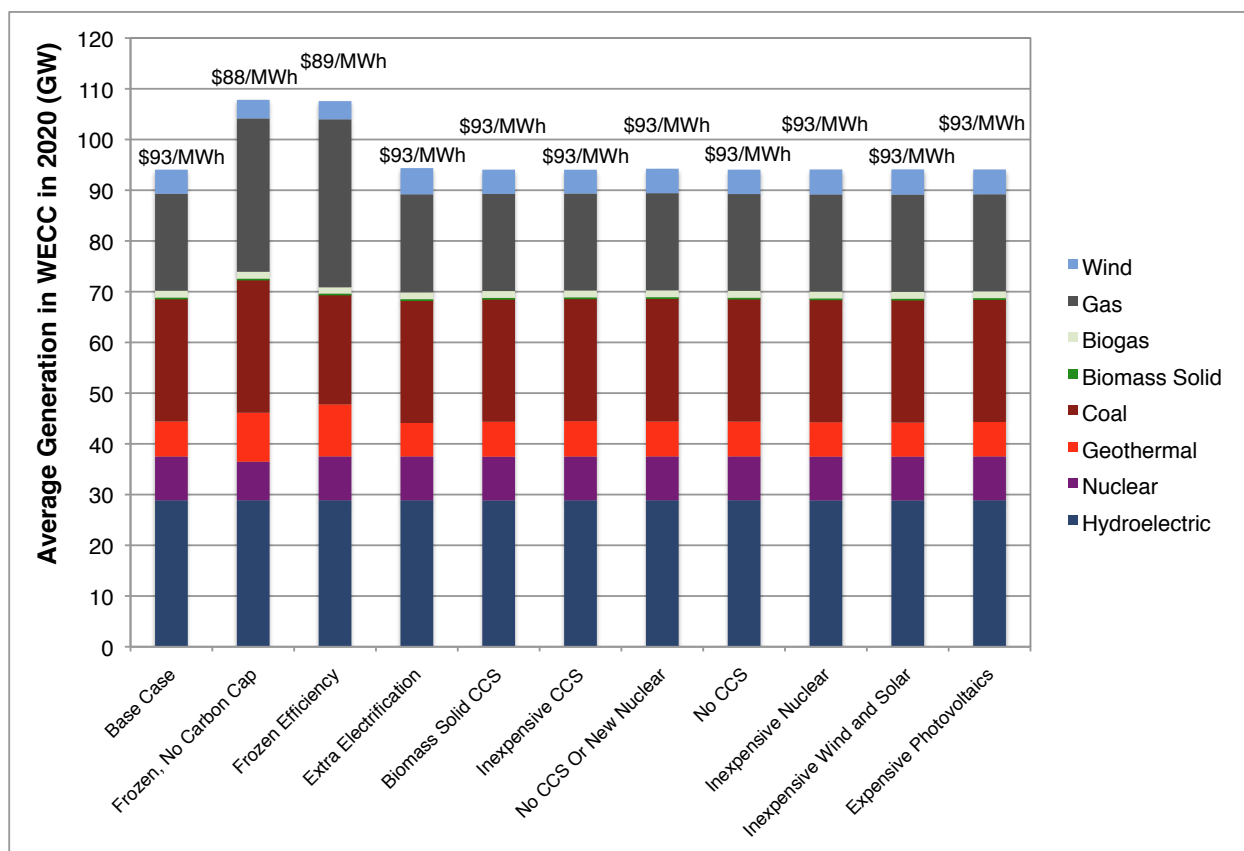
Figure 10-10. *Average generation by fuel and average power cost ($2007/MWh) in 2020 for all scenarios. To convert into yearly energy totals in GWh per year, multiply average GW by 8760 hours per year. Note that the average generation and power cost are dominated by load profile rather than carbon policy or generator cost in the 2020 timeframe. Power cost per unit of electricity is lower in the frozen efficiency scenarios because sunk costs are spread over more units of electricity relative to scenarios with aggressive energy efficiency measures.*
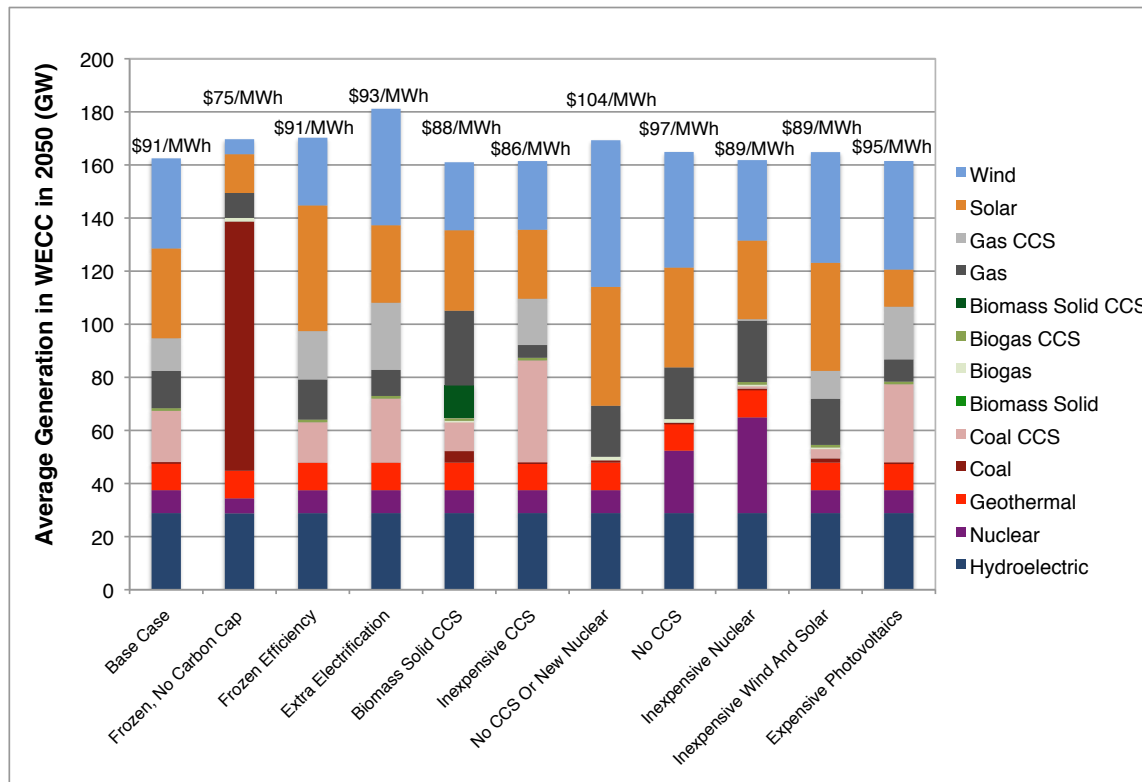
Figure 10-11: *Average generation by fuel and average power cost ($2007/MWh) in 2050 for all scenarios. To convert into yearly energy totals in GWh per year, multiply average GW by 8760 hours per year. Note that the power cost is similar in all scenarios except for the Frozen, No Carbon Cap scenario.*

Scenario	Biogas	Biogas CCS	Biomass Solid CCS	Coal	Coal CCS	Gas	Gas CCS	Geothermal	Solar	Nuclear	Hydroelectric	Wind	Power Cost [$2007/MWh]
Base Case	0	1.0	0	0.2	19.3	14.0	12.3	10.4	33.9	8.6	28.9	33.9	91.0
Frozen, No Carbon Cap	1.3	0	0	93.9	0	9.4	0	10.4	14.6	5.6	28.8	5.6	75.1
Frozen Efficiency	0	1.0	0	0	15.2	15.1	18.2	10.4	47.4	8.6	28.8	25.5	90.9
Extra Electrification	0	1.0	0	0	24.1	9.8	25.3	10.4	29.2	8.6	28.9	43.9	92.6
Biomass Solid CCS	0.1	0.9	12. 4	4.3	11.3	28.2	0	10.4	30.3	8.6	28.9	25.6	88.4
Inexpensive CCS	0	1.0	0	0.1	38.4	4.8	17.4	10.4	26.0	8.6	28.9	25.9	86.8
No CCS Or New Nuclear	1.3	0	0	0.8	0	19.2	0	10.4	44.8	8.6	28.8	55.2	103.9
No CCS	1.3	0	0	0.1	0	19.5	0	10.4	37.6	23.5	28.9	43.5	96.8
Inexpensive Nuclear	0	1.0	0	0.4	1.5	23.4	0.2	10.4	29.6	36.0	28.9	30.3	88.9
Inexpensive Wind and Solar	0	1.0	0	1.6	4.1	17.4	10.5	10.4	40.7	8.6	28.9	41.7	88.6
Expensive Photovoltaics	0	1.0	0	0.1	29.4	8.4	19.8	10.4	14.0	8.6	28.9	40.9	95.1

Table 10-3*: Average WECC-wide generation by fuel in 2050 for all scenarios. This data is a tabular representation of Figure 10-11. All units are in average GW, except for the cost of power, which is in $2007/MWh. To convert into yearly energy totals in GWh per year, multiply average GW by 8760 hours per year.*
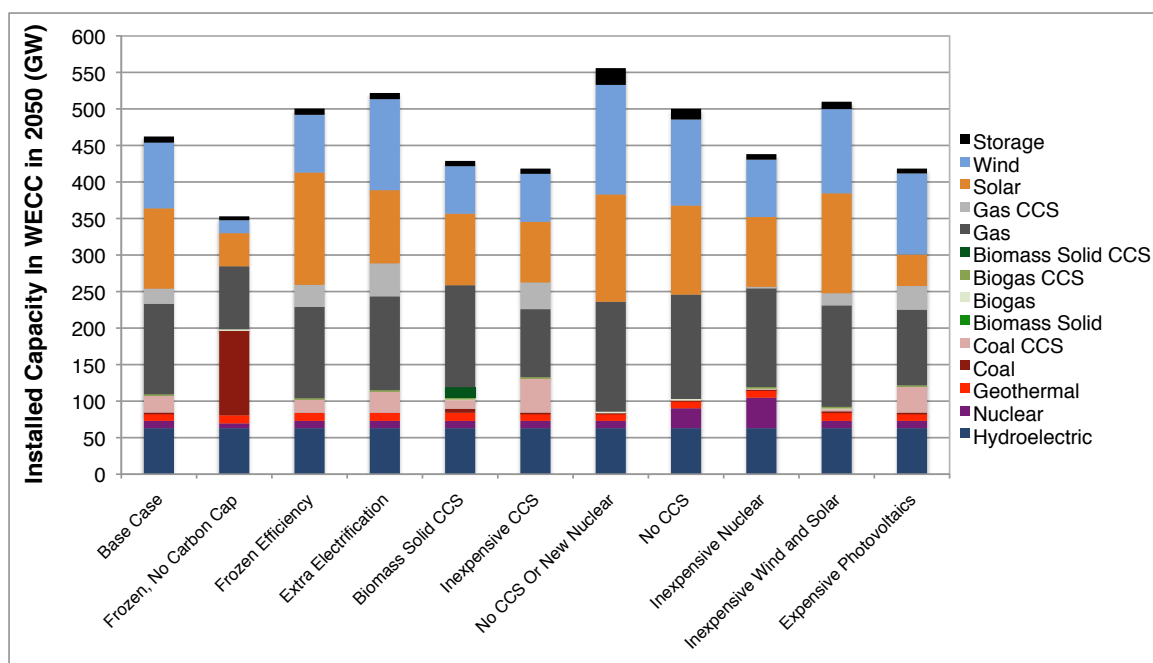
Figure 10-12: *Generator and storage capacity installed throughout WECC in 2050 for all scenarios considered in this study.*
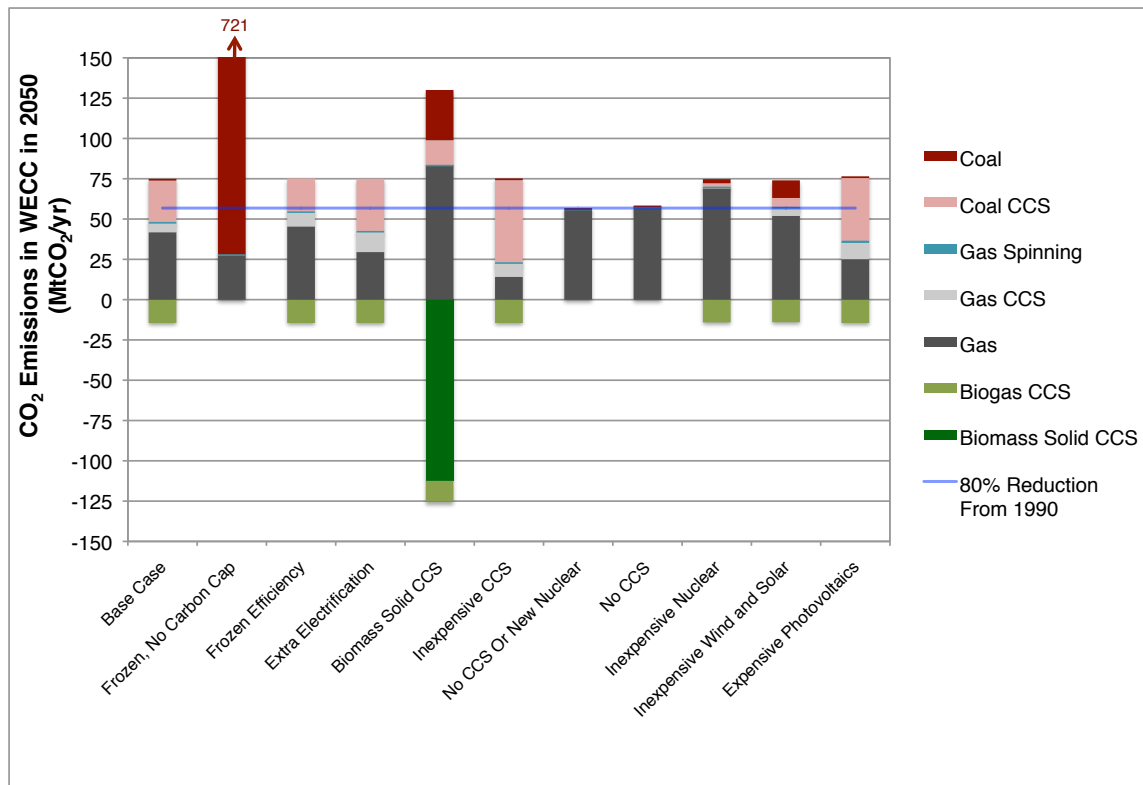
Figure 10-13: *Yearly CO$_2$ emissions across WECC in 2050 for all scenarios. The 2050 target of 80% emissions reduction relative to 1990 levels (61 MtCO$_2$) is shown for reference – this level of emissions is reached in all scenarios except for 'Frozen, No Carbon Cap' and 'Biomass Solid CCS' scenarios. CCS of biomass solid and biogas results in net negative emissions, thereby compensating for natural gas and coal emissions while remaining within the 80% emissions reduction cap. 'Gas Spinning' represents the additional emissions incurred from running gas-fired generation at part load, and is generally small owing in part to the extensive use of spinning reserves from hydroelectric and storage in 2050.*
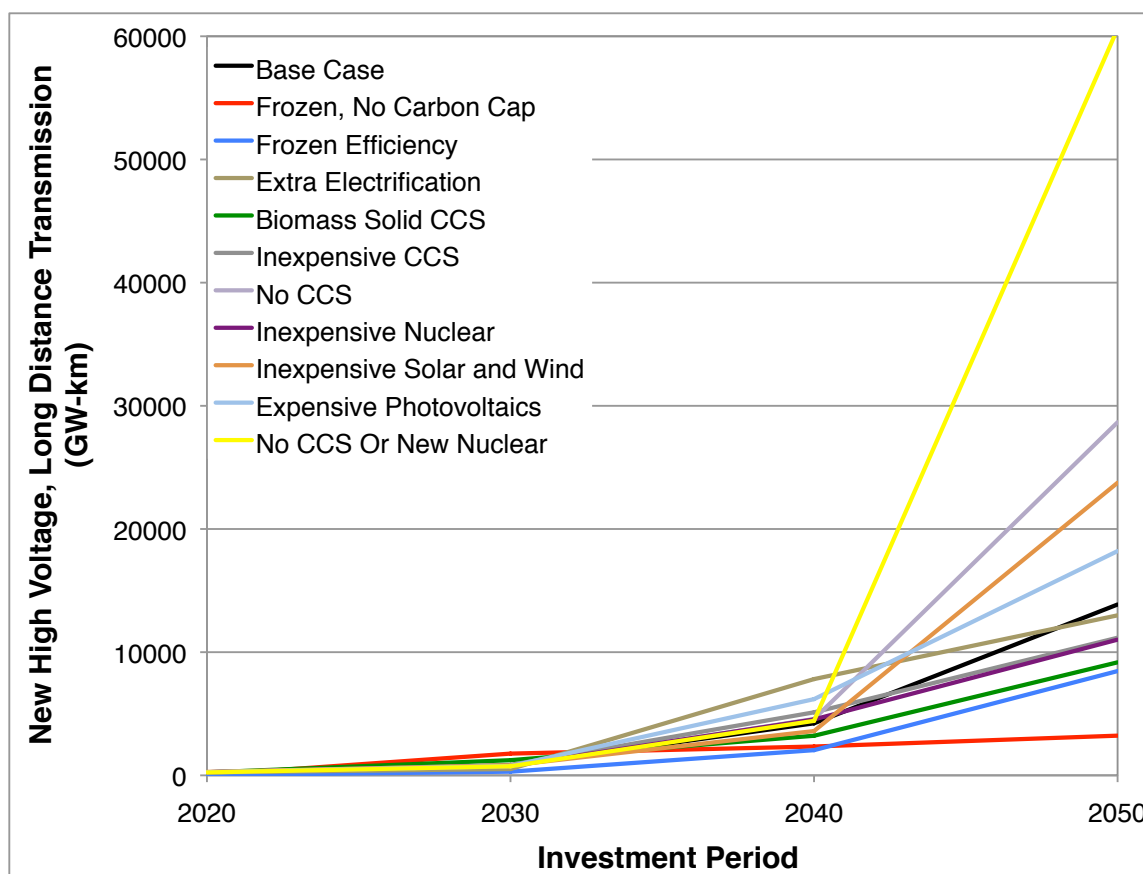
Figure 10-14: *New high-voltage, long-distance transmission built as a function of investment period, for all scenarios explored in this study. This figure does not include investment in smaller, local transmission and distribution lines, nor does it include small transmission lines that connect new generation projects to the larger transmission grid, although these costs are included in the SWITCH model.*

10.6 Biomass Solid CCS Scenario

The Biomass Solid CCS scenario is constrained to reduce carbon emissions to 100% below 1990 levels by 2050, making a carbon-neutral electricity grid. Biomass solid is sequestered via integrated gasification combined cycle CCS technology, a type of generator that is modeled to have a power conversion efficiency of 26%, which is relatively low with respect to gas-fired and coal-fired generation. The poor efficiency originates from extra energy consumed when using biomass as a feedstock and energy consumed in the carbon capture system. This low efficiency means that biomass solid CCS accounts for only 8% of the total WECC-wide energy produced in 2050. However, as shown in the dark green bar in Figure 10-13, another important role for bio CCS is in emission reduction: 112 $MtCO_2$/yr is sequestered from biomass solid and 13 $MtCO_2$/yr is sequestered from biogas. This total of 125 $MtCO_2$/yr sequestered from bio sources is double the carbon cap of 61 $MtCO_2$/yr in 2050. Of the total biomass solid fuel available to the electricity sector, 75% is sequestered by 2050.

Sequestering carbon from bio sources is a carbon-negative activity. By compensating for emissions from fossil fuel generation, bio sequestration enables significant generation from non-CCS natural gas (18%) and coal (3%) – the largest fraction of any scenario investigated in this study. The persistence of non-CCS fossil fuel generation in the Biomass Solid CCS scenario suggests that, if given the opportunity to sequester carbon from solid biomass, the electric power sector can accommodate further emission reductions beyond carbon neutrality. The power cost in 2050 for the Biomass Solid CCS scenario is 2.8% ($2.6/MWh) lower than the Base Case scenario (Figure 10-11), further corroborating the ability of the grid to go carbon negative.

10.7 High CCS Penetration: Inexpensive CCS and Expensive Photovoltaic Scenarios

In the Inexpensive CCS scenario in 2050, coal-fired CCS generation provides inexpensive low-carbon baseload power and replaces solar, wind and gas generation relative to the Base Case scenario. With 48 GW installed WECC-wide (Figure 10-12), coal CCS accounts for 24% of total energy (Figure 10-11), up from 12% in the Base Case scenario. Almost all of this coal CCS generation is built in load areas far from California, with 56% of new capacity installed in Canada. Gas-fired CCS generation is built in California, with 5 GW installed in the state out of a WECC-wide total of 37 GW. The Inexpensive CCS scenario produces power at a cost 5% lower than in the Base Case scenario due to the extensive deployment of low-cost CCS generation.

Similar results are obtained in the Expensive Photovoltaic scenario. Due to the high cost of photovoltaics, large amounts of wind power are installed in addition to coal-fired CCS generation to meet load. Only 9% of total electricity in 2050 is generated from photovoltaics in this scenario (Figure 10-11), the lowest amount of any scenario with a cap on carbon emissions. Despite the similar resource availability of solar thermal and central-station photovoltaics, no solar thermal generation is installed in this scenario by 2050. In this study, the projected cost of solar thermal with or without thermal energy storage is found to be prohibitively high relative to other low-carbon generation options. The Expensive Photovoltaic scenario produces power at a cost 4% higher than in the Base Case scenario.

The percentage of power from CCS generation exceeds 30% by 2050 in only two scenarios, reaching 31% in the Expensive Photovoltaics scenario and 35% in the Inexpensive CCS scenario. These scenarios demonstrate that CCS generation may contribute large amounts of electricity to the grid. However, widespread CCS availability and cost-effectiveness are highly uncertain in the 2050 timeframe. We do not explore the sensitivity of CCS deployment to fuel price in this study.

10.8 New Nuclear: Inexpensive Nuclear and No CCS Scenarios

While existing nuclear generation is kept running through 2050 in all carbon cap scenarios examined in this study, new nuclear is installed in only two cases: the Inexpensive Nuclear and No CCS scenarios. In both of these scenarios, the installation of nuclear power contributes greatly to meeting the 2050 carbon cap.

In the No CCS scenario, average all-in capital costs for new nuclear capacity remain at $4.92/W in 2050 as in the Base Case scenario. The removal of all CCS generation options forces the installation of 17 GW of new nuclear capacity, exclusively in Canada. A concomitant WECC-wide cost increase of

6% ($5.8/MWh) over the Base Case scenario is incurred (Figure 10-11). Five GW of additional compressed air energy storage capacity (Figure 10-12) is also deployed in the No CCS scenario to help replace CCS capacity present in the Base Case scenario. Non-CCS gas-fired generation produces 12% of power (Figure 10-11), and is responsible for virtually all WECC-wide electric power sector emissions (Figure 10-13) in the No CCS scenario in 2050.

In the Inexpensive Nuclear scenario, nuclear average all-in capital costs decline to $2.62/W by 2050, making it an economical option for low-carbon baseload power. In total, 42 GW of new nuclear capacity is installed across WECC (Figure 10-12) in order to meet rapidly rising demand, with 21 GW of this capacity installed in Canada. Little new nuclear capacity is installed in load areas near California and none is installed inside California itself due to the enforced ban on new nuclear within the state. In this scenario, nuclear outcompetes coal and gas CCS relative to the Base Case scenario. Non-CCS gas-fired generation produces 15% of power in 2050.

Using the cost and generator availability assumptions of the Base Case scenario, new nuclear capacity is not optimal to install, even in a carbon-constrained electricity grid, due to the availability of many other low-carbon supply options. The No CCS and Inexpensive Nuclear scenarios show nuclear power to act as a fail-safe for the cost and/or availability of other generation options. However, the lack of Canadian wind data in the current version of SWITCH may be one reason for large-scale installation of nuclear in Canada. We plan to obtain and integrate Canadian wind data for future studies.

10.9   Inexpensive Solar and Wind Scenario

The Inexpensive Solar and Wind scenario explores an electricity grid dominated by intermittent renewable generation. In this scenario in 2050, 25% of total WECC-wide generation originates from wind power and 25% originates from solar power, a total of 50% of generation from intermittent renewable sources.

The Inexpensive Solar and Wind scenario creates a power system that is reliant on new transmission (Figure 10-14) to move energy spatially, but is not as reliant on energy storage (Figure 10-12) to move energy temporally. It should be noted that storage does provide an important role in providing sub-hourly ancillary services to balance the large amounts of intermittent generation found in this scenario. Should storage costs decrease faster by 2050 than projected in this study, storage might participate more actively in inter-hourly energy arbitrage and enable deeper penetration of intermittent renewable energy.

10.10 No CCS Or New Nuclear Scenario

The No CCS or New Nuclear scenario represents the most extreme scenario of any presented here in terms of intermittent generation, with 33% of power from wind and 27% from solar in 2050. Relative to the Inexpensive Wind and Solar scenario, the lack of new nuclear power forces the installation of extra wind and solar capacity, along with additional transmission and storage capacity (Figures 10-12 and 10-14). The largest new transmission lines in this scenario are installed to bring Wyoming wind west to demand centers. Both battery storage and compressed air energy storage are installed to mitigate the intermittency of wind and solar, with 6 and 12 GW

installed by 2050 respectively. The cost of power in 2050 is the highest of any investigated in this study at $104/MWh, $7/MWh higher than is found in the Inexpensive Solar and Wind scenario.

One of the potential weaknesses of the SWITCH model is that each optimization is based on a limited set of hourly intermittent renewable generation: 144 distinct hours per investment period in this study. As discussed above, the dispatch verification addresses this issue by testing the investment decisions on a full year of load and hourly intermittent renewable generation data after the completion of each optimization. The dispatch verification step checks whether SWITCH has installed sufficient capacity to successfully meet hourly load for a full year. As the No CCS Or New Nuclear scenario has the highest percentage of intermittent generation of any scenario investigated here, it represents one of the most difficult scenarios to model with SWITCH. The dispatch verification shows that 1 GW of additional peaking capacity near to wind generation in Wyoming is required to meet load and reserve margins. This amount of capacity is small relative to the total installed capacity of the system (Figure 10-12), indicating that the optimization is producing a reliable electric power system. While the SWITCH model does not have the necessary capabilities to assess grid stability issues that may occur at large intermittent renewable penetration levels, it is an important step in renewable integration modeling with the goal of designing a power system that is able to integrate 60% intermittent renewable energy while successfully functioning on many timescales.

10.11   Frozen, No Carbon Cap Scenario

The Frozen, No Carbon Cap scenario assumes frozen energy efficiency and does not include a cap on carbon emissions. In this scenario, a large amount of new coal-fired generation is built by 2050 (Figure 10-12). This is the only case with substantially (17%) lower power cost than the Base Case scenario (Figure 10-11). CO_2 emissions in this scenario (Figure 10-13) are 721 $MtCO_2$/yr across WECC, 252% of 1990 WECC power sector emissions. This level of emissions is more than 12 times higher than the 2050 power sector emissions target of 80% below 1990 levels. This scenario demonstrates that under the Base Case cost assumptions present in the version of SWITCH model used here, coal is the least expensive form of generation in WECC. Inclusion of a carbon cap increases the cost of power, but external costs from global warming, criteria air pollutants, health impacts, and environmental and ecological degradation associated with coal mining, transport and combustion are likely to be very large (NRC 2010A), and are not reflected in the cost of power.

10.12   Load Profile Scenarios: Base Case, Frozen Efficiency, and Extra Electrification

The sensitivity of the optimal future power system to differences in energy efficiency, vehicle electrification and heating electrification is explored through three different load profiles. Load duration curves for these profiles can be found in Figure 10-15 and hourly plots by load type can be found in Figure 10-16. In the Frozen Efficiency and Extra Electrification scenarios the load profile is changed relative to the Base Case scenario but all other generator and carbon emission assumptions are held constant.
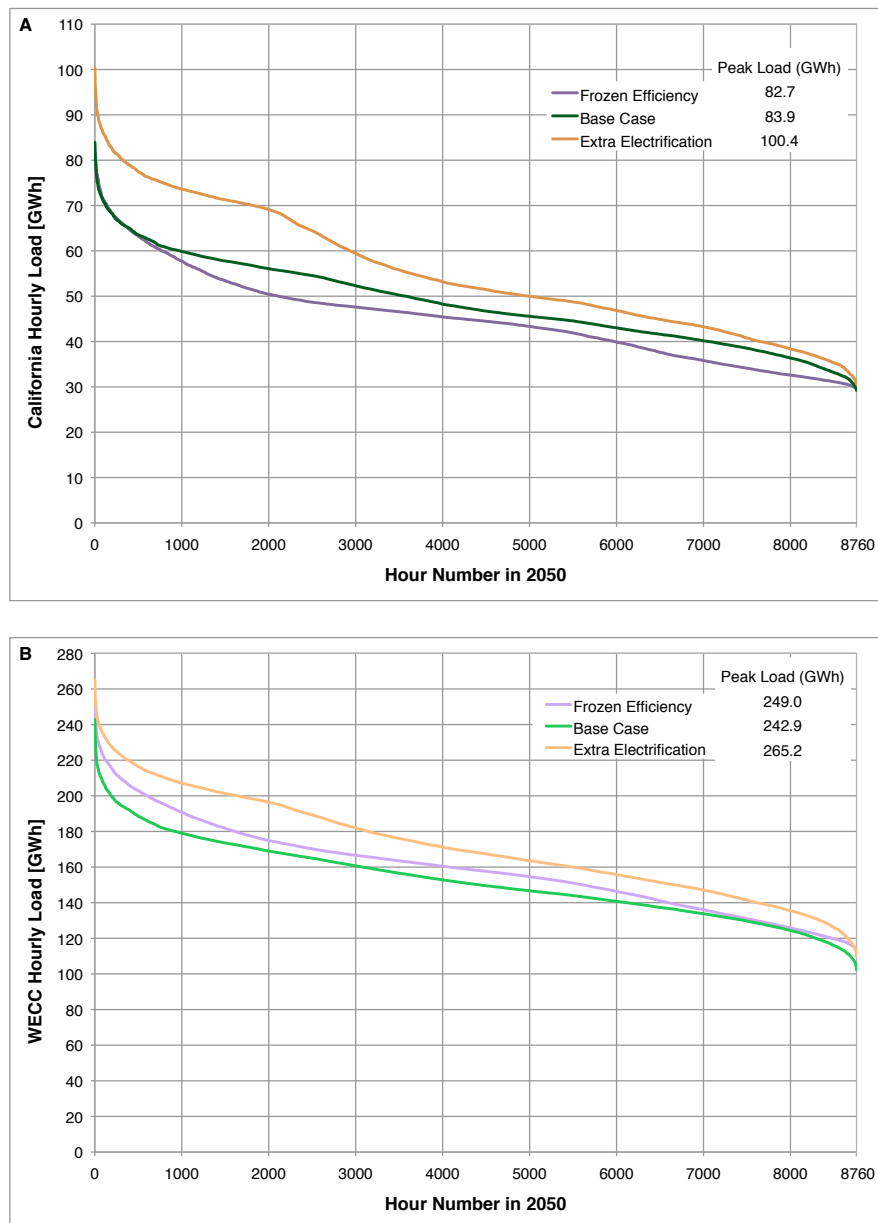
Figure 10-15: *Load duration curves for 2050 for (A) California (B) all of WECC, including California.*
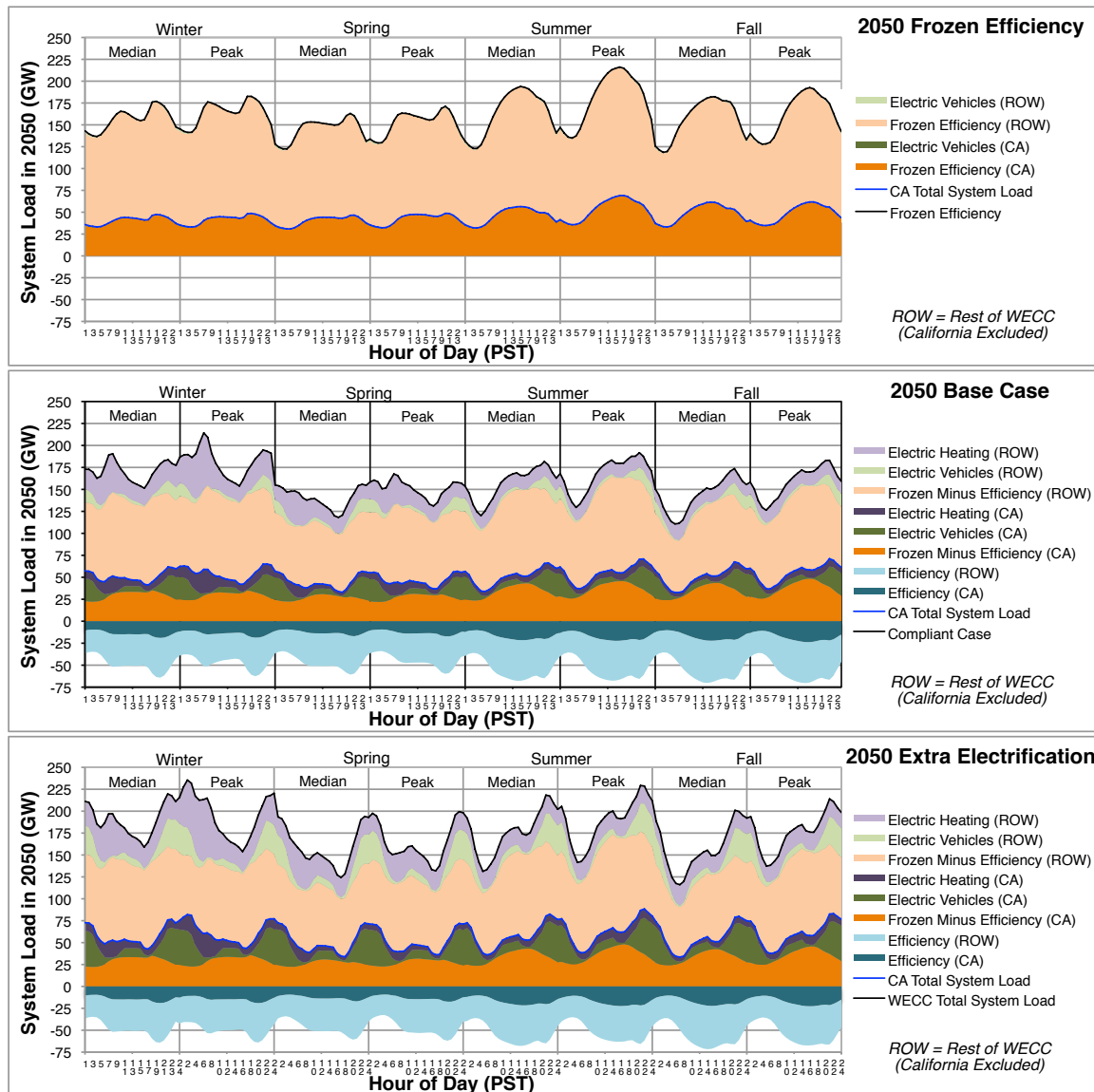
Figure 10-16: *Hourly load profiles by load type for the Frozen Efficiency, Base Case and Extra Electrification load profiles in 2050. For each season, the day with the peak load hour and the day with the median load are shown. 24 hours of data per day are plotted. Vertical gray lines divide distinct days. 'Frozen Minus Efficiency' represents the load profile after efficiency measures have been taken. 'Efficiency' is depicted here as negative load, representing the difference between the frozen efficiency load profile and the same load profile including energy efficiency reductions.*

The Base Case load profile includes substantial efficiency, vehicle electrification and heating electrification and, as a result, peaks at night. The Extra Electrification load profile includes aggressive amounts of vehicle and heating electrification above and beyond that which is found in the Base Case load profile. The night-peaking behavior of the Base Case profile is therefore amplified in the Extra Electrification profile.

For the Frozen Efficiency load profile, each hour from the 2006 load profile is scaled up by a uniform factor based on load projections. A small amount of electric vehicle load is included, but the EV demand does not significantly change the character of the load profile. This load profile therefore retains a diurnal shape similar to that found in present day, with the yearly peak coming in the early evening of hot summer months. The Frozen Efficiency load profile does not include aggressive energy efficiency measures.

The effect of projected load profile shape on the optimal temporal generation profile is shown for 2050 by comparing the plots in Figure 10-17. Relative to the Base Case load profile, the Frozen Efficiency load profile promotes solar generation due to the near-coincidence of peak load and peak solar generation. The Extra Electrification load profile has the opposite effect relative to the Base Case – electric vehicle and heating loads occur primarily at night and therefore favor wind generation over solar. Consequently, the Frozen Efficiency scenario has the highest amount of energy generated from solar in 2050 of any case explored here, whereas the Extra Electrification scenario has the second highest amount of energy generated from wind in 2050 of any case explored here (the No CCS and No New Nuclear scenario has the most energy generated from wind). In all three load profiles cases, meeting load relies extensively on gas-fired generation with and without CCS to firm intermittent solar and wind generation. In all three scenarios, at least 40% of power is generated by intermittent sources: 42% in the Base Case scenario, 43% in the Frozen Efficiency scenario, and 40% in the Extra Electrification scenario.

Of the SWITCH scenarios investigated here, the Frozen Efficiency scenario has the largest penetration level of energy from photovoltaics. This scenario also has the largest generation deficit in the dispatch verification phase, pointing to operational difficulties associated with photovoltaic intermittency and the need to account for them in the investment optimization. Specifically, 4 GW of peaking capacity in the Desert Southwest is added in the dispatch optimization phase of the Frozen Efficiency scenario. This peaking capacity is added to compensate for an increase in net load due to the decline in photovoltaic output ahead of the decline in load on summer evenings. The additional 4 GW of capacity required is small relative to the total installed generation and storage capacity of greater than 550 GW throughout WECC. An enhanced hourly sampling methodology in the investment optimization to take these operationally difficult times into account could reduce the magnitude of additional generation required in the dispatch optimization.
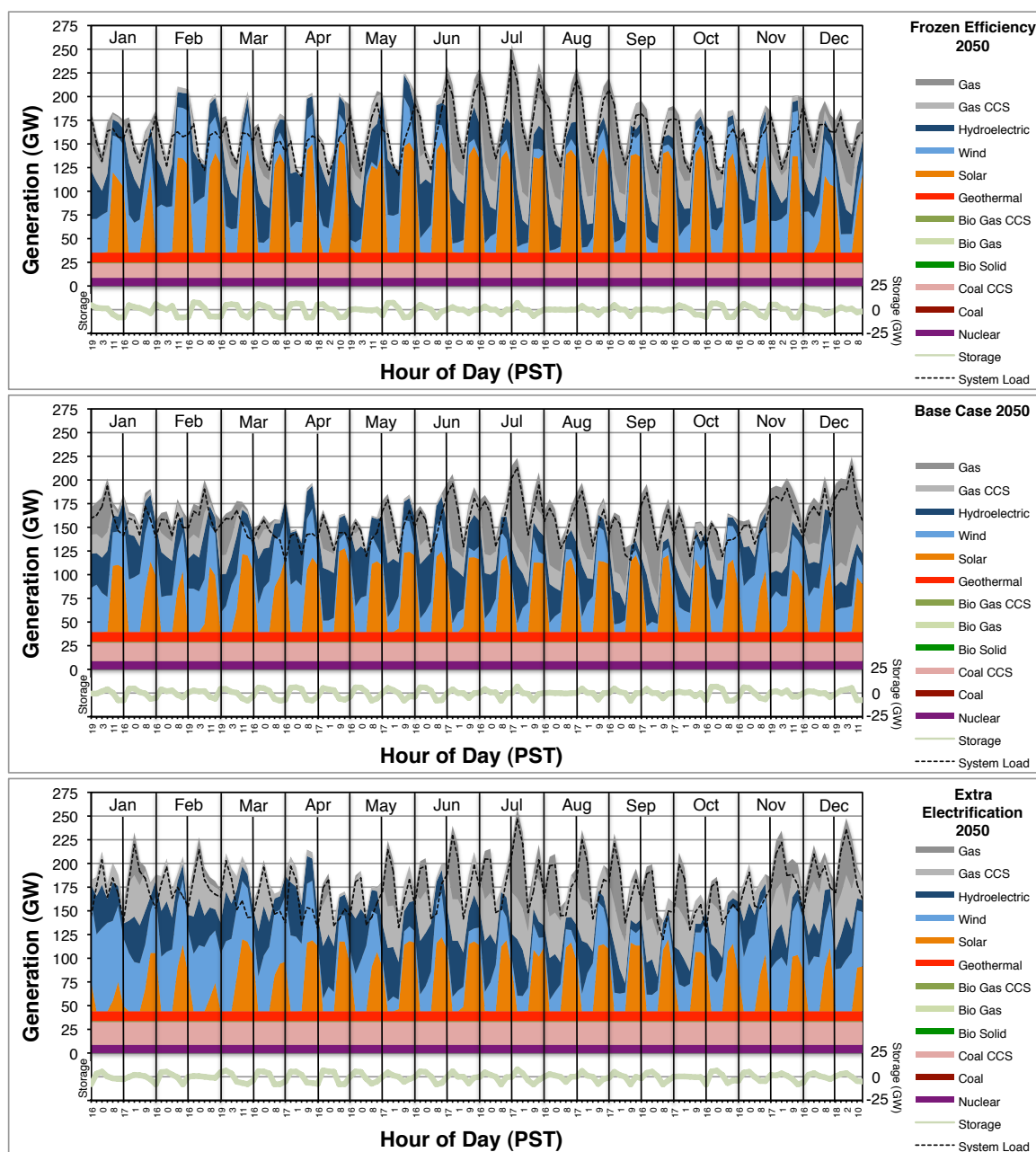
Figure 10-17: *Hourly dispatch of the for the Frozen Efficiency, Base Case and Extra Electrification load profiles for all of WECC in 2050. Each plot depicts six hours per day, two days per month, and twelve months per year. Each vertical line divides different simulated days.Optimizations are offset eight hours from Pacific Standard Time (PST), and consequently start at between hour 16 and hour 19 of each day. The system load line does not equal the total generation in each hour due to energy storage and losses in transmission and distribution. The hourly dispatch of storage is shown in light green below each generation plot, with negative values corresponding to energy storage and positive values corresponding to energy release.*

10.13 Discussion and Conclusions

The WECC electricity system in 2050 has a diverse set of generation options that can cost-effectively meet aggressive carbon reduction targets. The specific technologies that should dominate the future power system generation mix will be determined by a combination of factors including technological feasibility, cost and policy.

Electricity costs stay relatively constant among a range of possible scenarios in which carbon emissions are capped. While this result is in part dependent on projections of declining generator capital costs, sensitivity analyses show that two of the most uncertain future supply options – photovoltaics and CCS – are not individually essential with respect to the cost of electricity. In all carbon cap scenarios investigated here, the total power system cost increases roughly in proportion to load, so while the large-scale electrification of heating and transportation do add to the total amount spent on electricity, the delivered $/MWh cost of power is stable through 2050. It should be noted that, as calculated by SWITCH, the cost of power does not include the cost of implementing energy efficiency measures, installing electric heaters, or upgrading the distribution system to handle large electric vehicle loads. While providing many benefits and helping to avoid other expenditures, the aforementioned costs will further increase the cost to the consumer of decarbonizing the electric power system.

Electricity decarbonization is found to be expensive relative to not decarbonizing (externalities of carbon emissions notwithstanding), but using advanced modeling tools like SWITCH and increasing electricity coordination over a large area allows the cost of electricity to stay relatively low, even with deep decarbonization. Carbon and energy trading between regions is important to keep power costs low.

Nuclear and CCS have potential to be attractive low-carbon baseload power in the future. With the assumed costs, generating electricity from CCS can lower the cost of power while meeting carbon emissions targets. Installation of new nuclear power is shown to be a backstop against rising power costs, but new nuclear does not make an appearance in the Base Case scenario optimal power system. Sequestering biomass allows for greater carbon flexibility in a carbon-constrained grid, but this technology option, along with other CCS technologies, needs significant development to improve efficiencies and demonstrate viability for large-scale grid penetration.

Installation of new electricity storage helps to reduce the cost of power and to increase intermittent renewable penetration, but does not appear to be essential to the future deployment of intermittent renewables on the hourly timescale. Natural gas is very important in firming intermittent renewables on the hourly timescale in all scenarios investigated here, but could be in part exchanged for storage at higher cost. Natural gas and hydroelectric generators, as well as storage, are utilized extensively to provide sub-hourly load balancing. Sub-hourly load balancing does not appear to be a major limitation for achieving deep carbon dioxide emissions reduction in a future electricity grid with up to 60% of energy from intermittent renewable generation. Using operating reserve requirements similar to rules evaluated in the Western Wind and Solar Integration Study (GE Energy 2010), it is found that the majority of spinning reserves can be provided by hydroelectric power and storage technologies. The use of demand response to balance load is a topic for future study.

The coupling of aggressive energy efficiency measures and large amounts of vehicle and heating load can generally be accommodated by the electric power system. However, distribution grid requirements for these load profiles are not addressed in detail in this study.

The relative fractions of wind and solar deployment are a function of the temporal characteristics of load, with increasing levels of vehicle and heating electrification favoring wind power over solar power. Despite their intermittency, both wind and solar power appear poised to supply large amounts of inexpensive, low-carbon electricity to the electric power system of the future.

11. BEHAVIOR MODEL

11.1 Introduction

Studies quantifying the potential for greenhouse gas emission reduction from behavior changes are often focused on the short term and include a wide range of behaviors. For example, Laitner 2009 formulates his behaviors in a 2x2 matrix with purchasing/investment decisions on one axis and duration of behavior on the other axis. Dietz 2009 considers the potential for GHG savings across a range of actions from weather stripping, one time set points, and ongoing behavior. Both studies estimate energy or GHG savings in the short term, i.e. less than 10 years into the future. This work focuses on long term potential for ongoing behavior change since habitual actions can be difficult to address, can take a long time to change, and their impacts on emissions will depend on the energy system.   We focus on consumer actions since consumer purchases represent 70% of GDP. Future work should consider the role of businesses and industry and how they might interact with changes in consumer behavior in areas such as service oriented business models, integrative design, sustainable, metric based supply chains, closed cycle, closed loop design, etc.

Historical adoption rates in diet, recycling, and health are sufficient to suggest that long term behavior changes affecting energy consumption are possible.   A detailed characterization matrix of attributes and barriers for many energy saving behaviors is described and long term adoption rates estimated based on correspondences with historical behaviors.   Behaviors that reduce GHG emissions today may have less effect when future energy systems already have low GHG emissions. We quantify potential savings from behaviors in a future low-carbon energy system for California, using results from the energy system modeling work in this report. The 2050 energy system features deep energy efficiency, de-carbonization of electricity supply, electrification of building heating, and partial de-carbonization of transportation fuels from bio-fuels and/or electrification.

We have formulated a long-term residential consumer behavior model. It includes a mini-database of non-energy and energy-related historical behaviors such as smoking, seat belt usage, recycling, and dietary trends. We chose to focus on "habitual" behaviors that may be difficult to legislate or require by law, and do not include purchase decisions or actions such as weather stripping which will be modeled in the building energy efficiency and electrification areas of this report.

A core list of behaviors is listed in Table 11-1 and a detailed characterization matrix has been developed (Table 11-2). Each behavior -- both historical and energy related actions -- is characterized with this matrix and each measure is cross-compared for similar attributes and barriers. Estimation of behavior adoption in 2050 is informed by the following: extrapolation of existing trends, existing market segmentation and survey frameworks, and through utilization of historical behavior trends and our characterization matrix.   Finally GHG savings for each measure is estimated using a life cycle assessment decomposition into GHG savings components for California (Jones 2011).

Long-term behavior changes can contribute GHG savings of 6-19% in 2050 and can make as large a difference as various high cost technology options. Greater GHG reduction is found from behavior related transportation fuel reduction than end-use electricity reduction, and behavior related

energy savings constitute a key wedge toward meeting 80% GHG reduction targets relative to 1990. This long term perspective can hopefully lead to better alignment of behavior related policy considerations with overall energy policies.

An alternate view of the behavior model is to address the following question: given maximal effort at energy efficient technology deployment, clean electricity, and vehicle electrification, and low carbon biofuels, how much further behavior change is needed to meet long term climate change goals?

Area	Individual/Household Actions
Consumption	Recycle as much as possible - paper, plastic and metals
Consumption	Paper and packaging - purchase items with minimal packaging e.g bulk foods; 2-sided printing, less magazine subscriptions; no plastic water bottles
Consumption	Use rechargeable batteries
Consumption	Repair more, upgrade less; Extend life of PCs/electronics by 50%
Food/Diet	Healthier diet - less red meat and dairy, more plant based whole foods
Food/Diet	Waste less food by 25%
Food/Diet	Shift to more organic foods
Home Energy	Composting
Home Energy	Line dry clothes
Home Energy	Turn off lights/ unplug appliances, use smart power strips
Home Energy	Use oven less
Home Energy	Jog outside instead of treadmill
Home Energy	Cold water dish/clothes washing
Home Energy	Lower water tank temperature
Home Energy	Shorter showers
Home Energy	Tune up AC/ furnace filters
Home Energy	Lower thermostat in winter
Home Energy	Raise thermostat in summer
Home Energy	Unplug second refrigerator
Home Energy	Reduce security lighting, switch off outside decorative lighting
Transport	Drive less (Carpool, walking, biking, reduced distances, ...)
Transport	Ecodriving: reduce max speed, hard stops and starts, driver training
Transport	Telecommute once a week
Transport	Proper tire inflation, regular auto maintenance
Transport	Increase public transit usage
Transport	Reduce number of air flights; through stay-cations, teleconferencing

Table 11-1. *List of Behaviors considered for this study.*

Characterization Feature	Description
Attributes	Visibility to Others
	Visibility of Benefits to consumer
	Ease of Substitution
	Ease of Behavior
	Feedback Visible?
	Enabling long term technologies?
	Enabling Policies, campaigns?
Barriers	Habit
	Indifference
	Info/Education
	Institutional/Cultural
	Risk Aversion/Safety
	Economic Cost
	Physical (Infrastructure)
	Labor/Inconvenience
	Lack of Incentive/Pleasure
	Climate/Weather
	Persistence/Stickiness

Table 11-2. *List of attributes and barriers for behavior characterization.*

11.2   Model scope

We make a distinction between energy service and "lifestyle" changes that is often made in behavior change potential studies (e.g. BC Hydro 2007). Behavior change can clearly occur on many different levels and the distinction here – which can clearly be blurred – is that behavior changes can either lead to no change in "energy service" delivery, or it could lead to lower energy service. The latter is typically associated with the "lifestyle change" denotation and is typically not included in behavior potential studies. Examples of the former could include items such as turning off your lights when you are not in the room or powering down your computer when not in use or using cold water dishwashing/clothes washing which implicitly deliver the same quality of service or results as the old behavior.   But we do not include large ticket items such as buying smaller cars or moving from a single family 3000 square foot home to a smaller single family home or apartment with the implicit assumption that the level of service delivered is impinged in such cases or that "lifestyle" is changed. There is gray area here since we do include VMT reduction such as carpooling or biking and healthy diet.   These items could also be argued to be lifestyle changes but on the other hand, VMT reduction could result in other co-benefits such as more time to rest or read the paper or conduct phone calls, and in the case of diet, one could argue that folks with healthy diet can consume similar number of calories in similar proportions of fats/carbohydrates/protein to less healthy diets.

We do not explicitly include the impact of technology, although that is embedded in behavior models and certainly in a wider perspective, behavior guides all our choice from purchasing of new technologies to habitual actions. It is within the framework of historical trends that technological

improvements can abet greater adoption of what we call habitual behaviors. The historical trend toward eating more poultry for example may be helped by advances in food processing technology and the more ready availability of boneless chicken leading to greater consumption.

This interaction of technology with greater uptake of behavioral changes is certainly expected to continue. Two examples- the latter rather further out in terms of commercial readiness illustrate this interaction. In both cases, technology can abet lower GHG behaviors.

- Instant carpooling –Advances in instant messaging and cell phone technology could make it easier for commuters or drivers to share trips that could reduce overall vehicle miles travelled. Clearly barriers in moral hazard and trust would need to be addressed. Startups include Avego, iCarpool and Zimride.
- Artificial meat – if in-vitro meat can scale and find audience it may reduce the consumption of conventional meat. Obviously technology demonstration and market acceptance remain key barriers, but certainly innovative meat substitutes have played a role in vegetarian diets and low meat diets historically (dating to at least the 10th Century in China) and are expected to continue in the future. (Sterckx 2005)

Similarly, aggressive policy measures can encourage energy saving behavior. For example, a much higher gasoline tax may induce people to drive less, but it may need to be coupled with offsetting tax reductions to avoid being regressive.

11.3 Historical Trends

A set of historical adoption curves for five historical behaviors are show in Figures 11-1 to 11-6. S-curve adoption curves are found to fit the data very well and follow the functional form:

$$A + \frac{B - A}{1 + \left(\frac{x}{C}\right)^D}$$

where A and B are the starting and ending adoption rates, respectively. For example, recycling has increased from 6.5% recovery rate 40 years ago to close to 35% in 2006 (EPA 2008). For the purposes of comparing and quantifying these behaviors, we parametrize these S-curves by 10%, 90% adoption percentages and 10-90 transition times in years in Table 11-3. With the exception of drunk driving fatalities, it can be seen that the time associated with behavior changes can take decades. Clearly these are not perfectly correlates to the energy space. In particular, public health and safety items can be mandated by laws and regulations and inspections – seat belt laws and drunk driving for example, that may not easily translate to energy related behaviors.

Several trends are abetted by a number of contributing factors such as increased awareness (smoking, recycling), authority figure awareness (physicians and smoking), labeling (smoking), policies (recycling and alcohol and tobacco "sin" taxes), improved infrastructure on varying scales (e.g. recycling bins), and improved technology (ease of purchasing boneless chicken versus whole

chickens). Thus the final adoption rates are the result of many ongoing factors in information/awareness, infrastructure, and technology. Several energy behaviors can lend themselves to policy actions, education/awareness campaigns, labeling, and infrastructure to slowing increase adoption rates e.g. healthier diet, public transport, carpooling, etc.

Recycling has been on a steady upward climb in California for the past 20 years due to a number of factors and recently several communities have announced "Zero Waste" targets. On the other hand per capita generation of MSW is up 50% per capita in the U.S. since 1970 and we also note that VMT per capita is up 38% since 1970 in California.

Food calories per capita adjusted for losses and waste in the U.S is up 25% from 1970-2000, but the relative food loss and waste is down slightly from 30% to 27% of total food supply available for consumption.

We thus highlight four significant counter trends which have increased energy usage since 1970:
- Median size of new single family homes up 55% from 1970-2010 (Diamond 2004, U.S. Census 2011); enabled by many factors including cheap credit, mortgage deduction credit, higher incomes, cheap fuels, etc.
- Food supply and calorie consumption up 26% per capita (USDA 2003); enabled by social shifts, agriculture policy, technology improvements, dietary policy and guidelines, artificial sweeteners, larger portion sizes, etc. From 1960 to 2006 the rate of obesity increased in U.S. adults from from 13.4 to 35.1 percent (DHHS 2010).
- VMT per capita up 38% in California since 1980 (DOT 2011); enabled by many factors including increased income, more suburban housing, more cars per capita, etc.
- Higher generation of materials with per capita increase by 50%, especially plastics (EPA 2009B); enabled by multiple factors including technology, increased income, more packaging, etc.

These are all significant trends but each has been influenced by state and national policies and each can be mitigated with policy as well. We assume that these factors do not increase further unless noted in the other demand sections of the report. This downward consumption trend is certainly plausible at least in the short term due to the ongoing recession and the need for private de-leveraging. Government policies can affect these trends as well such as tax policy which could be made more favorable to apartment renters, and USDA education policies which focus on less consumption rather than specific dietary guidelines which may be confusing (Martin 2011).
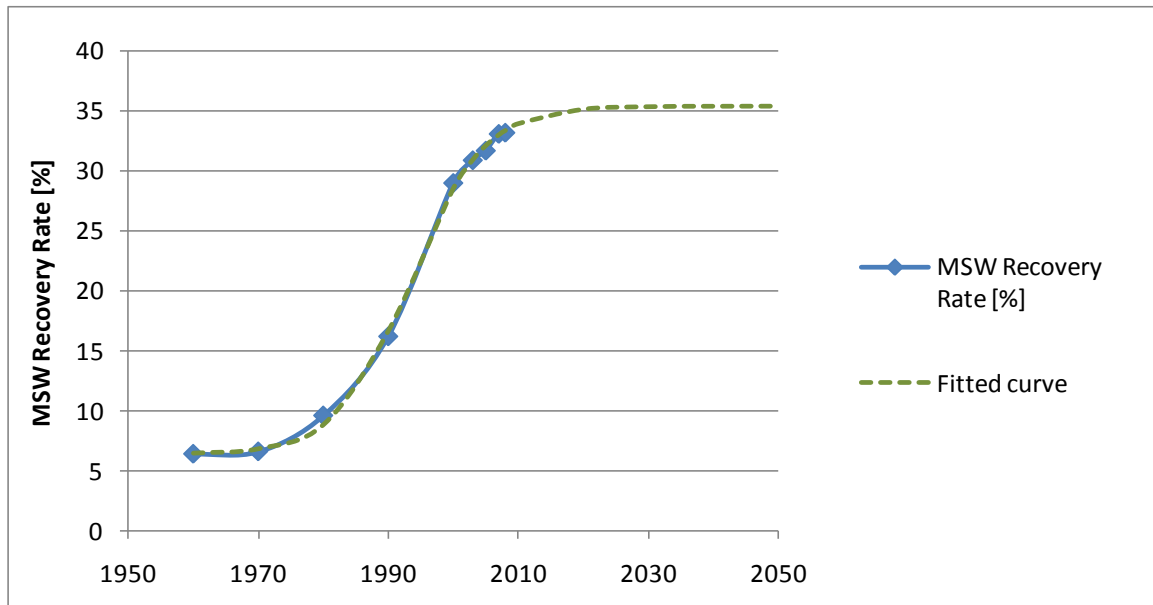
Figure 11-1. *Municipal solid waste (MSW) recovery rate for the United States (EPA 2009B). Data points are fit to adoption S-Curve.*
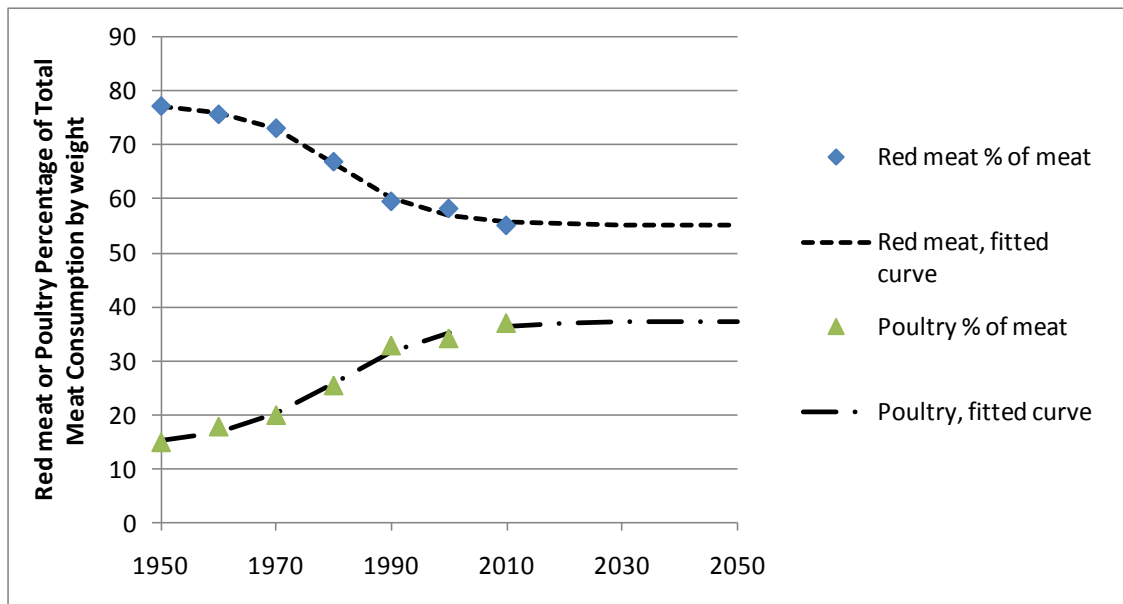
Figure 11-2. *Meat Consumption. (USDA 2003) Data points are fit to adoption S-Curve.*
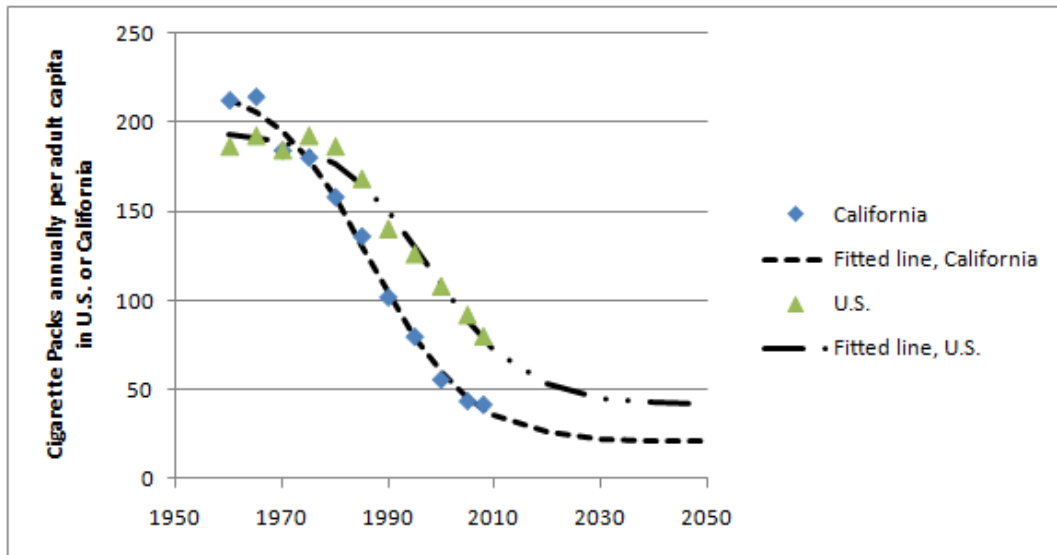
Figure 11-3. *Smoking – packs per adult capita for California (Pierce 2010) and the U.S (RX 2011). Data points are fit to adoption S-Curve.*
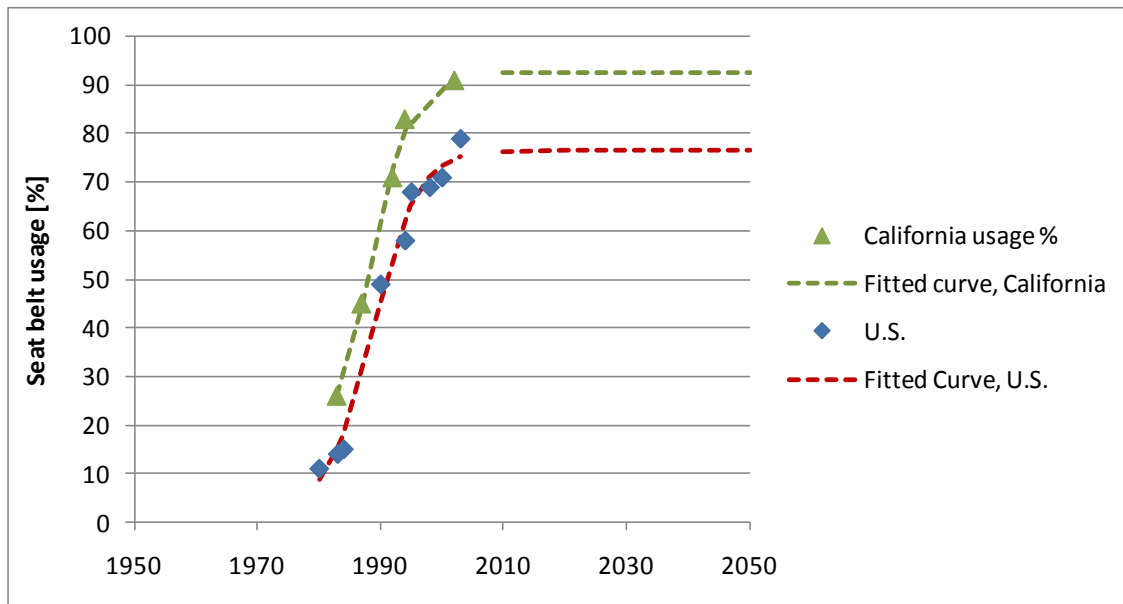
Figure 11-4. *Seat Belt Usage for U.S. (Dinh Zarr 2001, DOT 2008) and California   (Gantz 2002). Data points are fit to adoption S-Curve.*

127
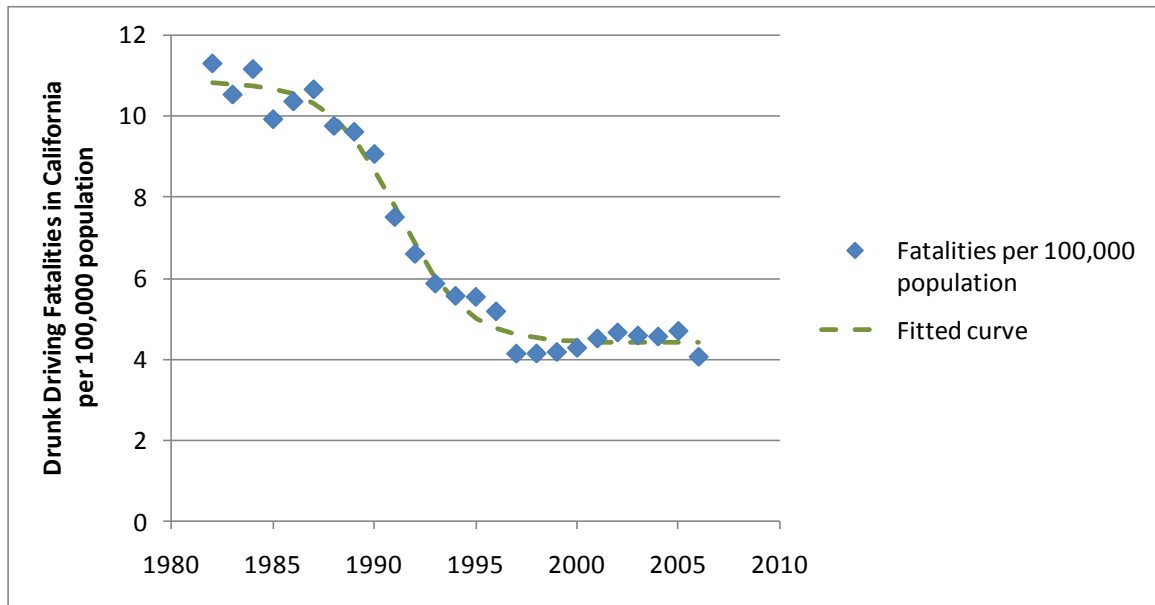
Figure 11-5. *Drunk driving fatality rate in California (Alcohol Alert 2010). Data   points are fit to adoption S-Curve.*
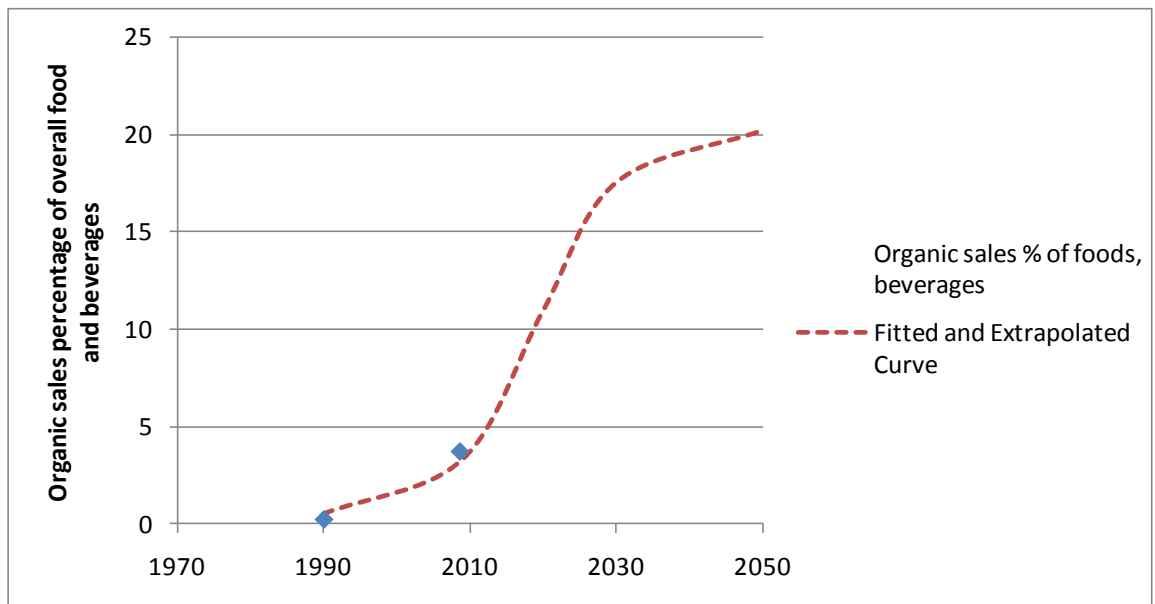
Figure 11-6. *Organic food percentage of total food and beverage sales (OTA 2010).   Data points to 2009. Fit curve extrapolated to 2050 to 20% adoption. In general, early   adopters in a population are estimated at about 20% of population and this fraction of   people expected to adopt organic food by 2050.*

Measure	10%	50%	90%	A	B	10-90% Time [years]
Recycling Rate, U.S.	1981	1993	2006	7%	35%	25
Seat Belt Usage, Calif.	1982	1989	1995	15%	93%	13
Seat Belt Usage, U.S.	1981	1989	1997	3%	77%	16
Drunk Driving, [fatalities per 100,000 pop.], Calif.	1987	1991	1995	10.9	4.4	8
Organic food, U.S. [1]	2006	2019	2032	0%	20%	26
Red Meat [% total meat wt], U.S.	1964	1980	1997	77%	55%	33
Poultry [% total meat wt], U.S.	1961	1980	2000	15%	37%	39
Smoking [annual packs per adult], Calif.	1967	1987	2007	223.0	20.7	40
Smoking [annual packs per adult], U.S.	1978	1998	2017	195.0	41.3	39
Yoga, U.S. [2]	2000	2010	2020	7%	7%	20
Vegetarian, U.S. [3]	1980	2000	2020	1%	10%	40

Table 11-3. *Characterization of historical behavior trends in recycling, diet and health.*

Notes:

[1] Organic food represents sales percentage of overall food and beverages and is projected to reach 20% in 2050.

[2] Recent results for Yoga (Yoga 2008) extrapolated to 2020

[3] Vegetarian rate[16] extrapolated to 2020

11.4   Behavior Model

A core list of behaviors is listed in Table 11-1. They include "home energy conservation" measures, food/diet actions, and transportation measures. Home energy conservation measures include turning off or reducing end use electricity uses such as lighting and electronics, lower thermostat settings in winter, higher thermostats in summer, and reduced hot water usage through cold water dishwashing and clothes washing, and shorter showers. In general we focus on ongoing or habitual actions. Thus we do not include items such as home weather stripping, purchasing of more energy efficient vehicles or appliances, since both of these could in principle be mandated by building/housing regulations and/or appliance efficiency standards. There is gray area between actions which entail "lifestyle" changes. We include measures such as healthier diet and more use of public transit, but do not include smaller houses. The former certainly entail lifestyle change but could also be argued to enhance quality of life if co-benefits result such as improved health and well-being, or less unproductive time spent in congested traffic.

Some behaviors are difficult to maintain or may have a low terminal adoption. For example, line drying clothes may be too troublesome to be widely adopted. Vegetarianism seems slow to grow

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[16] Data from various national polls: Roper (1994-1997), Zogby (2000), and Harris (2003-2008); U.K. data from Mintel (2005).

and we take 10% as an upper limit based on United Kingdom data. Similarly, limited data for regular activity such as yoga seems to suggest a flat or slightly decreasing trend.

Some measures have a take-back or rebound effect. For example, telecommuters may in fact use more home energy and take more trips of an errand nature while working at home, negating the energy savings that arise from less office energy use. We include a take-back reduction for telecommuting that is 25% of the GHG savings. No other take-back reductions are applied for other actions, however.

For each behavior a detailed characterization matrix has been developed (Table 11-2). Each behavior -- both historical and energy related actions -- is characterized with this matrix and each measure is cross-compared for similar attributes and barriers. Estimation of behavior adoption in 2050 can be informed by the following: extrapolation of existing trends including demographic trends, existing market segmentation and survey frameworks, and through utilization of historical behavior trends and our characterization matrix.

Here we utilize a survey framework to rate the attributes and behaviors of each behavior action . We use a committee of five behavior analysts within the LBNL/UC-Berkeley energy research community and take the average of their responses. Each behavior action, including historical behavior actions, are represented as an (i+j)th-dimensional vector with i entries for attributes, and j entries for barriers.

$$V_m = (a_1, a_2, a_3, ... a_i, b_1, b_2, b_3, ... b_j)$$

Attributes are rated on a scale of 1 to 5 for a low to high match to the attribute in question (e.g. ease of substitution, visibility of benefits). Similarly for barriers a high score indicates a more significant barrier (e.g. labor barriers, cultural barriers).

We then consider the vector distances between behavior vector V_m for action m and the set of historical vectors H_1, H_2, ... H_n as an indicator for the correspondence between behaviors. A lower vector distance between V_m,H_i than between V_m,H_j indicates a greater correspondence with historical action i than with historical action j.   Adoption rates in 2050 for action m are then estimated from weighted average of terminal adoption values for the three historical actions which best correspond with action m.   Similarly, a high adoption rate in 2050 is found by either taking the maximum terminal value of the corresponding historical action.

Adoption rates are tabulated in Table 11-4. Additional actions were also considered but did not contribute significantly to overall GHG reduction are not shown here (composting, rechargeable batteries, wider scale organic food adoption, etc). We do not use detailed S-curves for adoption over time but basically take the terminal value as that at 2050 and a linear rate of increase from 2011 for simplicity.

Action	2050 Nominal Adoption rate	2050 High Adoption rate	Change in Behavior
Increase Recycling	80%	90%	90% overall recycling rate*
Reduce Municipal Solid Waste	22%	35%	33% less waste
Drive less (carpool, biking, reduced distances…)	16%	37%	30% lower VMT
Ecodriving (including trucks)	50%	80%	Lower top speed, reduce hard stops and starts
Take public transit	22%	35%	Overall public transit miles increase by 200%
Reduce air travel	29%	49%	Reduce air travel mile by 30%
Telecommute to work	20%	35%	Telecommute 4 days per month
Healthier diet	28%	37%	Less red meat and dairy, more plant based food
Waste less food	12%	20%	Waste 25% less food
Turning off electronics	57%	80%	Turn off electronics when not in use
Line dry clothes	13%	20%	Line dry clothes instead of dryer
Lower thermostat in winter	69%	80%	Turn down thermostat at night
Raise thermostat in summer	83%	87%	Higher daytime thermostat setting
Cold water dishwashing and clothes washing	36%	80%	Use cold water instead of hot water

Table 11-4. *Modeled adoption rates in 2050. *Recycling "adoption rates" are not adoption rates among the population but rather indicate overall recycling rate as percentage of available recoverable material.*

Estimated Behaviors Savings

The calculation of GHG savings from behavior change has three important factors: (1) the energy associated with a given behavior; (2) the amount of potential energy efficiency savings associated with that behavior and (3) the carbon intensity associated with the fuels or electricity. For example, the production of a gallon of milk may have a given energy of production and distribution associated with it within the life cycle assessment boundary and this has associated GHG emissions with the current energy system. However over time, the energy associated with this consumption and production of milk may be reduced due to energy efficiency measures in the production of milk (production, pasteurization, bottling) and more efficient vehicles and concurrently carbon intensity may be reduced because of cleaner fuels (bio-based fuels for transport and/or cleaner electricity). Similarly for a reduction in vehicle miles travelled, there is improved vehicle efficiency over time coupled with cleaner fuels or vehicle electrification and cleaner electricity.

In addition, a fourth factor for CARB GHG accounting in the state is the boundary of energy expended or GHG emissions associated with the production of a product. Today imported emissions are not included in consumption or purchase of imported goods, so the LCA energy and emissions reduction would be reduced by the amount that is not currently counted in CARB GHG accounting conventions. Reduced consumption and recycling which leads to less energy and material inputs for production are two measures which are expected to have a relatively small

California emissions fraction, as the trend has been for more imported goods from exporting countries such as China (Edwards 2010).

Thus a decomposition of GHG savings due to behavior changes can be written as:

$$GS(t) = ES_{LCA} * ES_{EEI} * CI(t) * BF(t)$$

where:

t = time
GS(t) = GHG savings
ES_{LCA} = LCA Energy Saved per unit of physical output (e.g. kg steel)
ES_{EEI} = Energy savings reduction due to continuous energy efficiency improvement
CI(t) = Carbon intensity [CO2-eq/ unit energy]
      BF(t) = LCA boundary factor

It is worth emphasizing that current studies of GHG savings from actions e.g. recycling or diet quote GHG savings for a given snapshot in time, for a certain efficiency of production and distribution for the associated product, and for a certain carbon intensity associated with the energy of production.

We consider two energy system regimes for calculating the effects of long term behavior change:
    (1) "RPS/LCFS" regime where more expensive clean energy requires regulation to achieve significant market share. In this case marginal demand reduction reduces both fossil and clean energy demand. For example, demand reduction of 20% translates into a 20% reduction in fossil based energy and clean energy production starting points. In this case, there can be diminishing returns to behavior changes as the overall energy system becomes cleaner e.g. through progressively higher RPS and LCFS standards.
    (2) "Expensive" fossil fuel regime. Here marginal demand reduction is assumed to directly displace fossil fuel demand because clean energy supply sources are inexpensive relative to fossil fuels and/or because of a sufficiently high price of carbon. In contrast to the RPS/LCFS regime, there are constant returns to behavior change since behavior change energy savings translate one to one with reduced fossil fuel consumption, up to the point where there is no fossil fuel remaining in the system.   (Behavior model assumptions for both regimes are detailed in Appendix 4).

Figure 11-7 show the reduction to California CARB emissions under the nominal and high behavior adoption rates of Table 11-4 for the high in-state biofuels case in the "RPS/LCFS" regime. Several salient points can be made with this scenario for 2050. First CO2 reductions are 14.6MMt CO2eq for the high adoption case and 9.1 MMt for the nominal adoption case. This represents 9-15% emissions reduction from the high in-state biofuels starting point of 97MMt CO2. For the high adoption case, recycling contributes about a third of the behavior savings and the transportation measures (telecommuting, driving less, taking public transit, eco-driving and reduced air travel) contributes about one-half of the emission reductions. Note that these savings include both energy and non-energy savings (methane and nitrous oxide) but the bulk are from energy savings. Strictly

speaking we could have split out these behavior savings into energy and non-energy sectors, but the team chose to keep these together to represent overall projected behavior savings.

Home energy conservation is a small contributor (<5% of total behavior emissions reduction) in our modeling. This is attributed to multiple factors in the future energy system: improving building shells and insulation will reduce the demand for space heating and space cooling while transitioning to highly efficient heat pump space heating and water heating will consume less energy; and finally the assumption that electricity is supplied by much cleaner sources.

In both nominal and higher adoption case, we observe that some behavior components bend downward over time (driving less) and overall behavior savings reaches a maximal value and then rolls off after that. This is because the rate of de-carbonization from the adoption of low carbon technologies (biofuels and electric vehicles) is greater than the rate of VMT reduction from behavior changes.

Behavior savings for the high in-state biofuels scenario with nominal adoption and high adoption savings in the "expensive fossil fuel" regime where all marginal demand savings translate into fossil fuel demand reduction are show in Figure 11-8. Here there are constant returns behavior change (up to the point at which all fossil fuels have been displaced) and much larger overall savings. CO2 reductions are 39.2MMt CO2eq for the high adoption case and 20.6MMt for the nominal adoption case. This represents 21-40% emissions reduction from the high in-state biofuels starting point of 97MMt CO2. As before, transportation measures dominate with almost 80% of the savings. We did not study the impact of food waste reduction and MSW reduction on in-state biofuel production but the reduction in waste is also offset by the increased recycling rate.

A matrix of output for each action will be presented in a separate analysis paper detailing the amount of energy savings or VMT reduction, the carbon-intensity reduction (CO2/unit energy or CO2/unit mile) and finally the amount of GHG savings. The energy savings is important to keep in mind as the energy system becomes decarbonized because there will be other non-carbon savings associated with continued energy savings such as physical investment/infrastructure costs, other non-CO2 emissions, and resource consumption.
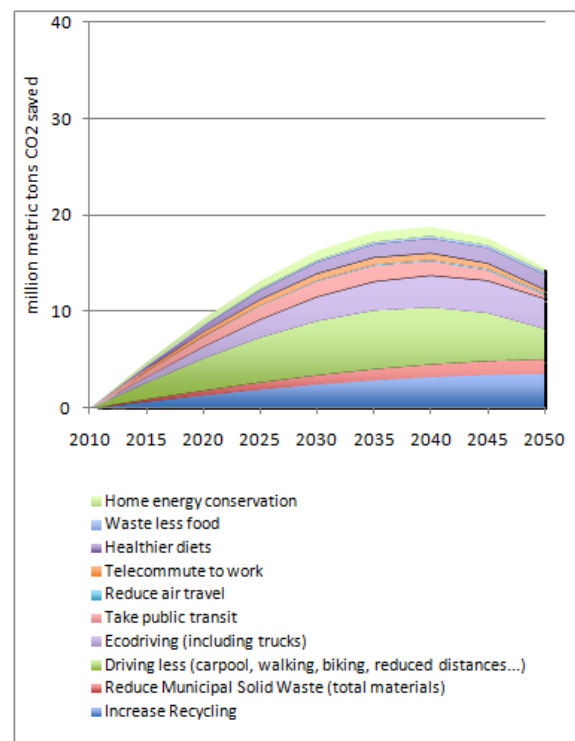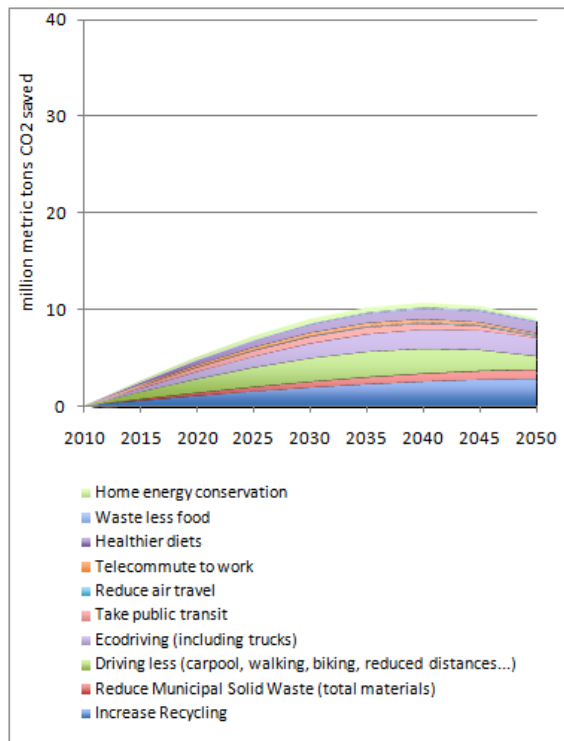
Figure 11-7. *Behavior change savings for the high in-state biofuels scenario with nominal adoption (left) and high adoption (right) savings in "RPS/LCFS" regime of higher cost clean energy.*
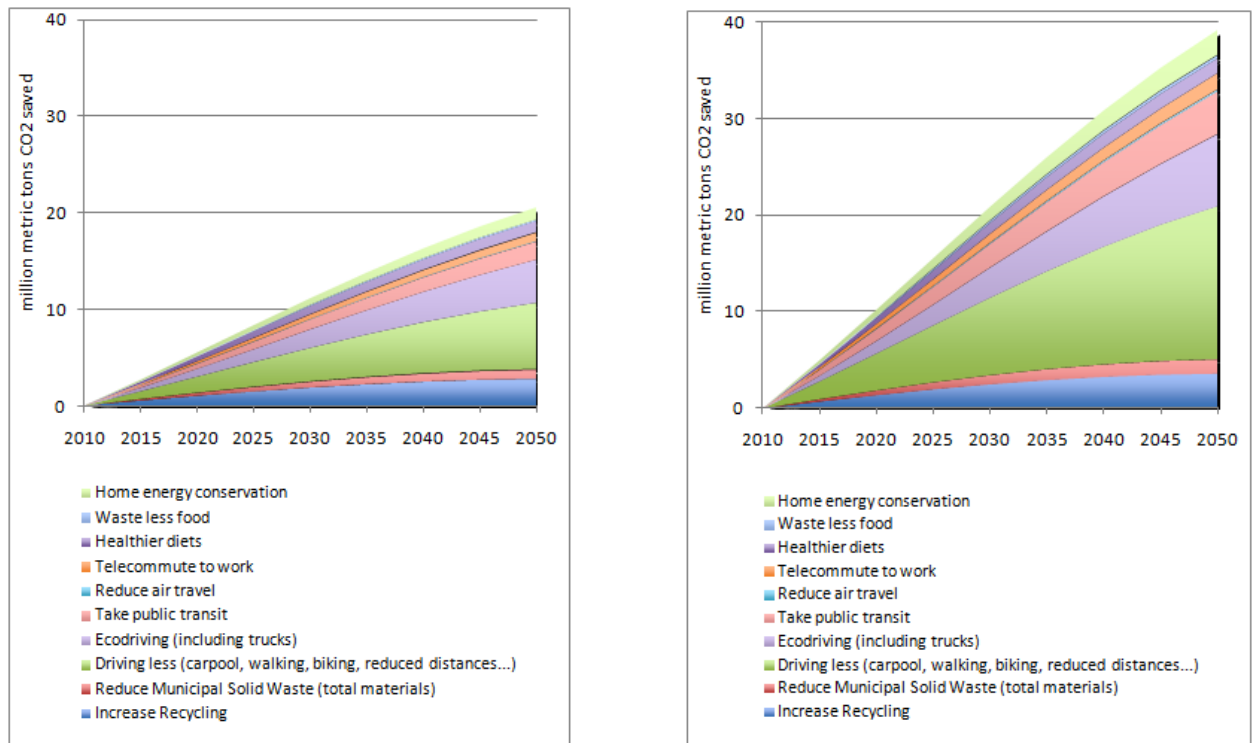
Figure 11-8. *Behavior change savings for the high in-state biofuels scenario with nominal adoption (left) and high adoption (right) savings in the "expensive fossil fuel" regime where all marginal demand savings translate into fossil fuel demand reduction.*

Overall savings from behavior change in 2050 are depicted in Fig. 11-9, again starting from the high in-state biofuels case. Transportation measures are seen to be the main contributor. Recycling, reduction in municipal solid waste, healthier diet and home energy conservation measures contribute as well. We will see in the next chapter that most emissions remaining in our scenarios are from fuel combustion and here we have shown that behavior actions that reduce fuel usage and transportation fuel in particular have a large impact on reducing GHG emissions.
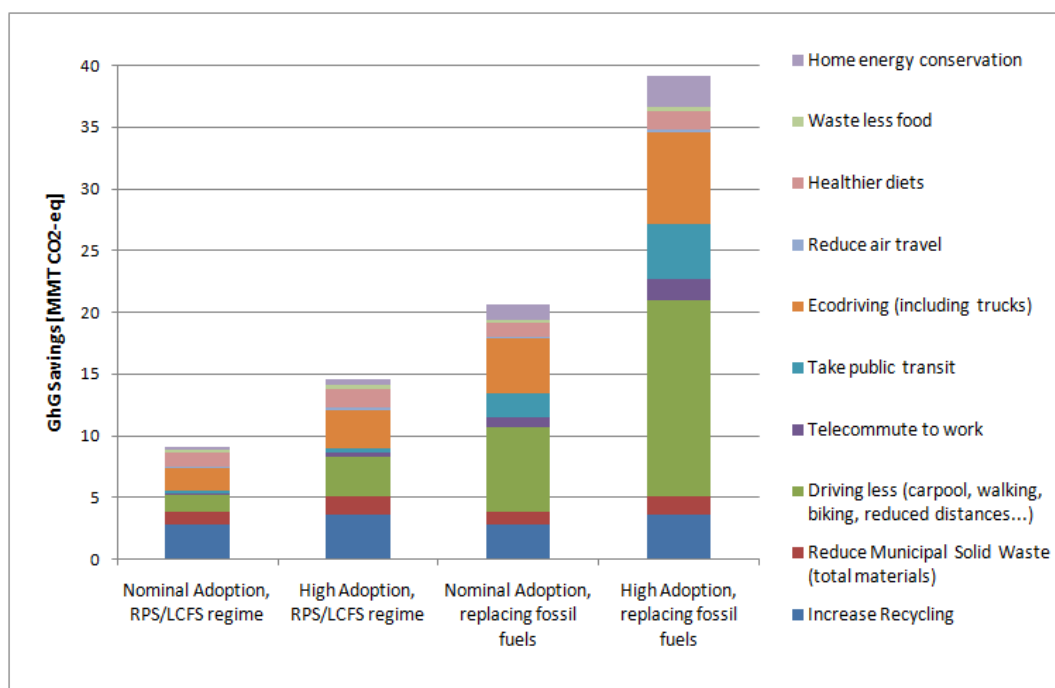
Figure 11-9. *2050 behavior savings from behavior change for nominal and high adoption for two treatment regimes, starting from high in-state biofuels case.*

Policy Implications

The largest impact items are transportation actions and increased recycling. Home energy conservation measures have smaller impact because of our assumptions regarding the evolution of the energy system. Transportation measures include smart growth policies (higher density developments with mixed use), traffic congestion charges to discourage use of passenger vehicles in central areas, increased funding for mass transit systems such as light rail and bus systems, incentives for carpooling, training programs for eco-driving and telecommuting energy savings optimization (Table 11-5). Clearly a large policy lever for transportation can be a higher gasoline tax and/or carbon charge for liquid fuel usage.

Here we would suggest that along with a concerted effort for long term energy system and supply changes as outlined in Sections 9 and 10 above, the state consider a set of policies focusing on reducing VMT, improving diets and increasing recycling/reducing solid waste. Reducing VMT can be done with measures that enable and encourage greater adoption of public transit, discourage use of automobiles, provide incentives for reduced single passenger vehicle use, etc. For recycling, strategies could focus on lower consumption and greater re-use, encouragement of zero waste programs, working with manufacturers to reduce packaging, encouraging re-use of products and re-use and recycle to be built into product design. Healthier diets can be encouraged by public information campaigns, increased food labeling, and junk food taxes.

136

Developing, testing, and implementing policies and technologies that can further abet the long adoption of these actions is an area for future study.

	Policy/Organization	Example Policies	Technology
Transportation			
Telecommute	Employers/ Companies	Flexible work policies; work at home protocols	Flexible office space; Improved software and hardware; improved commercial building controls
Reduced VMT	Smart growth (Integrated housing, transportation, commercial and land use planning), urban in-fill	SB375	Instant carpooling technology
	Employers/ Companies	Employer sponsored carpooling / shuttles	
	Federal, state or local taxation agency	Gasoline tax offset by reduced payroll tax or to provide alternate transit services	
	Various EU countries	Urban center higher parking fees, longer traffic lights, congestion charges (Rosenthal 2011)	
Public transit	Employer programs	Bus/rail subsidy through employer coupled with government incentives/rebates	
	Smart Growth policy	SB375	
Eco-driving	DMV, Driver's Education programs, Companies with large vehicle fleets	Eco-driving training and testing	Improved automotive feedback

Food and Diet			
Healthy diet	Federal, state and local jurisdictions	Public information campaign; Healthy food in schools; Food labeling; junk food tax	In-vitro meat
Reduced food waste	Federal, state and local jurisdictions	Public information campaign	
Recycling/ Less MSW generation	Zero waste Oakland	Zero Waste targets	
		Packaging charges	
		Rebates/ incentives for service and repair shops	

Table 11-5. *Policies, organizations, and technologies supporting long term behavior change.*

12. GHG EMISSIONS – SCENARIO RESULTS

12.1 2020 Emissions

We chose to focus this report on strategies and trajectories that meet the 2050 target and to then check that 2020 targets are met, rather than focusing initially on the 2020 target and then moving forward to meet the 2050 target. This approach of "beginning with the end in mind" ensures that long term targets can be met and hopefully circumvent any potential detours or "dead-ends" that might arise by focusing on the intermediate 2020 target. Secondly, this approach identifies long term programmatic needs or gaps which may not be required for meeting the 2020 target, but are essential for meeting the 2050 target. For example a large scale effort in the next decade to install unabated natural gas based CHP systems for low temperature heating may not necessarily be consistent with a shift toward electrifying industrial process heating. Similarly, the state may be able to meet the 2020 emissions target without a significant shift to electrified building heating but to meet the 2050 target it is probably necessary to align policy frameworks in the near term to facilitate this shift over the next four decades. Starting retrofitting and replacement activities too late again risks not meeting the target since end use equipment, systems and housing stock lifetimes can be long.

A table of CARB projected emissions in 2020 (ARB 2010C) and base case results from this analysis are shown in Table 12-1. A CARB table of foreseeable measures from October 2010 show about 62 MMt CO2-eq of additional reduction measures including low carbon fuel standard, 33% RPS and refrigerant tracking (Table 12-2). Both the CARB reference case with foreseeable measures and the base case from this study are within 5% of 2020 target of 427MMt CO2eq.

With ongoing, adopted and "foreseeable" scoping plan measures to 2020, emissions in 2020 are projected to be 445 MMt CO2-eq or within 4% of the target. Moreover, "cap-and-trade regulation would establish a declining limit (cap) on 85-percent of statewide GHG emissions[17]. The declining cap established in the regulation would ensure that all necessary reductions occur to meet the 2020 target, even if the estimated reductions from other measures fall short," according to CARB. For example, industry emission reductions could be 10-20MMt from cap and trade by 2020 with a tightening of the cap and with more industry inclusion as planned. Note that with foreseeable reductions, the state is meeting its energy emissions target but more than double its non-energy emissions target (63MMt vs 28MMt). This underscores the technical difficulty with meeting non-energy emission reduction targets which becomes even more acute in 2050 if current non-energy emissions trends continue.

The 2020 reference case from this report assumes a frozen efficiency and a frozen RPS from current levels and is thus higher than the 2020 CARB projection, which includes the 33% RPS and Pavley I vehicle emission standards. The 2020 base case from this work has lower electricity demand and industry demand than CARB resulting from the assumed technical potential energy efficiency

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[17] Cap and trade implementation in California may be delayed from its scheduled start date of January 2012, pending appeal of a Superior Court ruling in January 2011 that halt CARB's efforts to implement the cap-and-trade program. The ruling does not affect other AB 32 provisions in various stages of implementation and the appeal allows the further development of the cap and trade system.

savings and thus has lower emissions for these sectors. Landfill is also assumed to be sharply curtailed in the base case primarily from methane capture. Note that the 2020 base case does not necessarily include all CARB foreseeable reductions. For example SB375 (regional transportation planning) is not explicitly modeled in the base case. Otherwise both CARB and this report pursue energy efficiency measures and both include the 33% RPS electricity standard for 2020.

Since energy emissions appear be on reasonable track to meeting 2020 targets, we focus the remainder of this section on 2050.

Sector	2020 CARB [Million tonnes of CO2 equivalent]	CARB Forseeable emissions reductions [MMtCO2eq]	2020 CARB with foreseeable reductions [MMtCO2eq]	This Report: 2020 BAU case	This Report: 2020 Base Case [MMtCO2eq]
Transport	184	24	160	203	167
Power	110	13	98	128	87
Industry	92	0	92	104	75
Commercial/residential	45	12	33	50	38
Total, Energy emissions	431	49	382	485	367
Percentage from 2020 energy emissions target (399 MMt)	8.0%	na	-4%	14%	-8%
Landfills	9	2	7	9	1
High GWP	38	6	32	38	27
Agriculture/forestry	29	5	24	36	19
Total, Non-energy emissions	76	13	63	83	47
Percentage from 2020 non-energy emissions target (28 MMt)	170%		124%	196%	70%
Total, Energy & Non-energy	507	62	445	568	414
Percentage from 2020 target, 427 MMt CO2-eq	18.6%	na	4%	33%	-3%

Table 12-1. *CARB and CCC Base case emission in 2020.*

Greenhouse gas Reductions from Ongoing, Adopted and Foreseeable Scoping Plan Measures

Million tonnes of CO2 equivalent

Total of All Measures	**62.0**
Measures in Capped Sectors	**49.0**
Transportation	**24.4**
T-1 Advanced Clean Cars	3.8
T-2 Low Carbon Fuel Standard	15.0
T-3 Regional Targets (SB375)	3.0
T-4 Tire Pressure Program	0.6
T-5 Ship Electrification	0.2
T-7 Heavy Duty Aerodynamics	0.9
T-8 Meadium/Heavy Hybridization	0.0
T-9 High Speed Rail	1.0
Electricity and Natural Gas	**24.6**
E-1 Energy Efficiency and Conservation	7.8
CR-1 Energy Efficiency and Conservation	4.1
CR-2 Solar Hot Water (AB 1470)	0.1
E-3 Renewable Electricity Standard (20%-33%)	11.4
E-4 Million Solar Roofs	1.1
Industry	
I-1 Energy Efficiency and Co-Benefits Audits for Large Industrial Sources	0.0
Measures in Uncapped Sources/Sectors	**12.9**
H-1 Motor Vehicle A/C Refrigerant Emissions	0.2
H-2 SF6 Limits on non-utility and non-semiconductor applications	-
H-3 Reduce Perfluorocarbons in Semiconductor Manufacturing	0.2
H-4 Limit High GWP use in Consumer Products	0.2
H-6 Refrigerant Tracking/Reporting/Repair Deposit Program	5.8
H-6 SF6 Leak Reduction and Recycling in Electrical Applications	0.1
F-1 Sustainable Forests	5.0
RW-1 Landfill Methane Control Measure	1.5

Last Updated: 10/28/2010

Table 12-2. *CARB foreseeable measures for 2020 (CARB 2010).*

12.2   2050 fuel demand

Total fuel demand for 2008, the 2050 reference case, and the 2050 base case are shown in Table 12-3. Transportation fuel represents 57% of fuel demand in 2008. This fuel demand more than doubles in the reference case, but is reduced by 40% from 2008 in the base case.   Light duty vehicles have the largest reduction with aggressive vehicle electrification. Industry is reduced about 69% from 2008 fuel demand with the oil and gas industry reduced in size by about 75% from 2008. Building fuel demand is reduced threefold from 2008 to 2050, again from energy efficiency measures and electrification of heating. Fig. 12-1 shows that biofuel supply is insufficient to fully cover the base case liquid fuel demand for either the low in-state biofuels or high in-state biofuels if imports are capped to 25% of overall biofuels.

Sector	Subsector	2008 [billion gge]	2050 BAU [billion gge]	2050 Base Case [billion gge]
Transport	LDV	15.4	29.8	6
	Trucks	3.1	6.4	3.85
	Marine	1.52	3.0	1.1
	Aviation	3.7	15.0	3.4
	Buses	0.56	0.87	0.27
	Rail	0.24	0.37	-
	Total, transport	24.5	55.5	14.6
Industry	Non-oil and gas	4.1	4.8	1.9
	Oil and Gas	8	9.4	1.9
Buildings		6.1	9.3	2.1
Total fuel		42.7	79.0	20.5

Table 12-3. *Total fuel demand for 2008, 2050 reference and 2050 base case*.
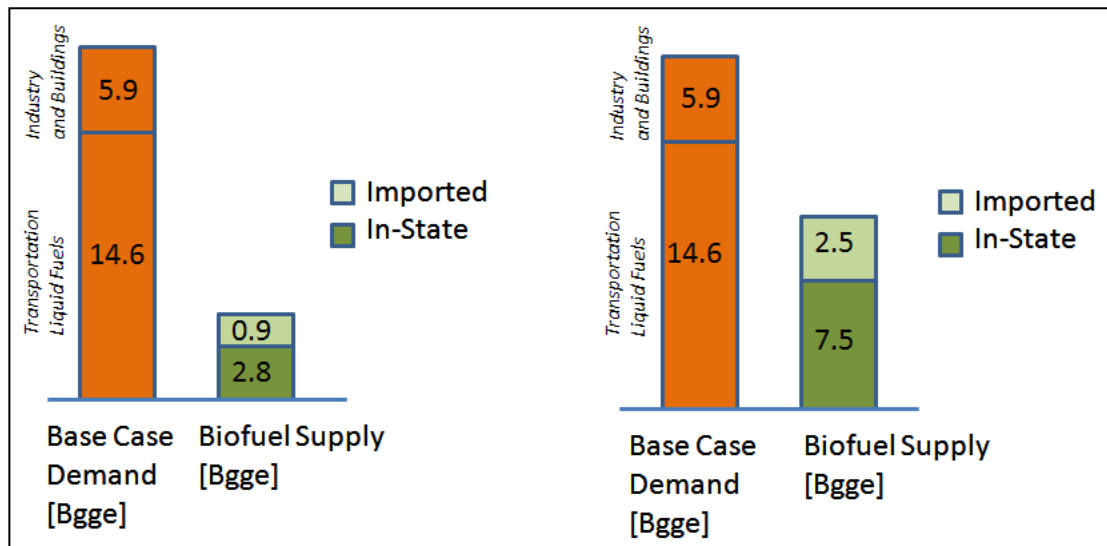
Figure 12-1. *Low in-state biofuels and high in-state biofuels compared to Base Case fuel demand. When imported biofuels are capped to 25% of overall biofuels, there is still 16.8 Bgge fossil fuel demand for the former case and 10.5 Bgge remaining fossil fuel demand in the latter case.*

Electricity demand is shown in Figure 12-2 reproduced from Section 7. The technical potential case succeeds in flattening overall demand to 2050 while the base case begins to sharply increase demand with electrification of vehicles and heating in about 2022, exceeding the reference case by about 7% in 2050. Total demand in 2050 is projected to be 424,000 GWh. About 38% of base case

electricity demand is seen to be from electrified heating and transport, with the bulk of this for new demand from transport (Figure 12-3).
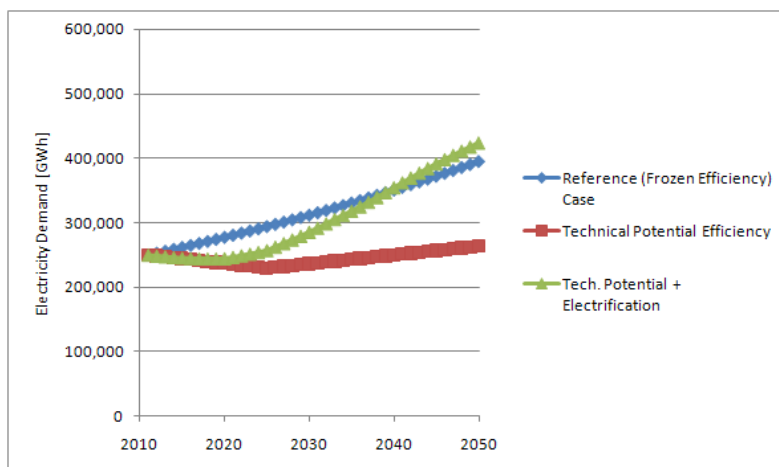
Figure 12-2. *Electricity demand for California to 2050 for the reference case, technical potential efficiency, and base case.*
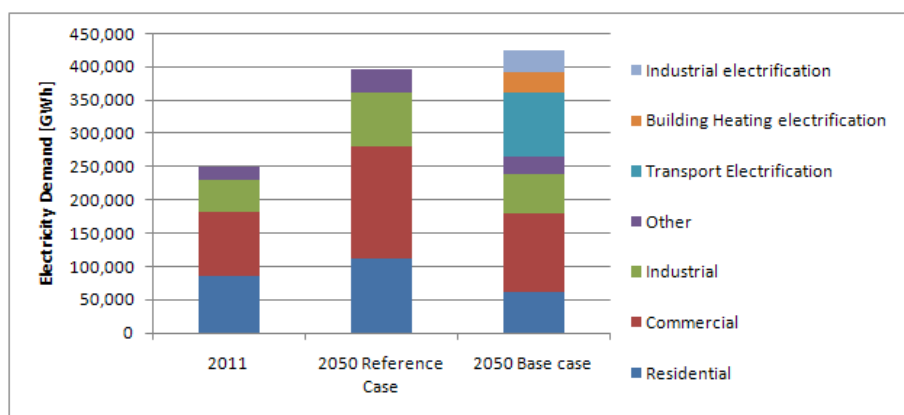
Figure 12-3. *Electricity demand components in 2011 and 2050 for California.*

12.3   2050 emissions

2050 California GHG emissions for the base case are shown in Figure 12-4. The impact of each of the four key elements taken by itself is shown and then the base case which combines all four

elements.   The important takeaway is that a portfolio of approaches is needed to meet the 2050
target (80MMtCO2eq) and that any one element on its own is insufficient and very far from the
target. The base case, which includes all four elements, is much closer to meeting the target but still
above the target at 130MMtCO2-eq.
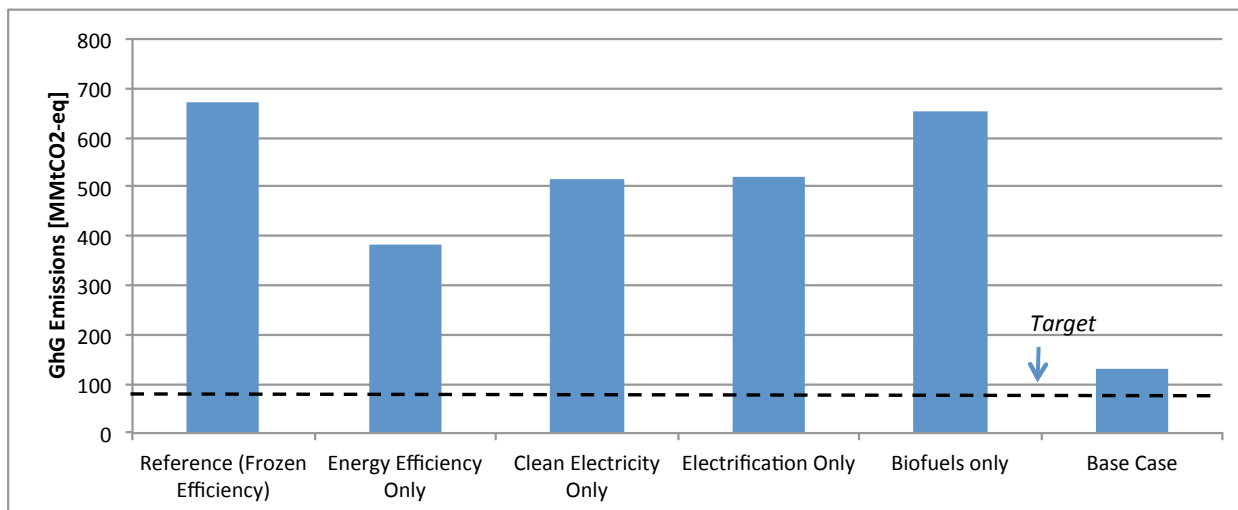
Figure 12-4. *2050 California GHG energy emissions. Base case include all four depicted elements
(technical potential energy efficiency, clean electricity, electrification, biofuels).*

2050 California GHG emissions for all the modeled scenarios are shown in Table 12-4 and a subset
of scenarios in Figure 12-5. All non-reference case scenarios assume technical potential efficiency
and electrification of heating and vehicles, and all but the biomass CCS assume at least 3.7Bgge
biofuel supply.   All modeled scenarios include a carbon cap on electricity emissions in the WECC:
100% CO2 reduction from 1990 electricity emissions or carbon neutrality is assumed for the
biomass CCS cases while all other cases require 80% CO2 reduction from 1990.   Several scenarios
can meet or come close to meeting the 2050 target of 80MMt CO2eq for energy emissions:

➢ high electrification with high adoption behavior savings (84 MMt);
➢ high in-state biofuels and high adoption behavior savings (82MMt);
➢ biomass CCS with high in-state biomass (79 MMt):
➢ high in-state biofuels and high biofuel imports (74MMt); and
➢ high in-state biofuels and high electrification (71MMt).

Scenario	Efficiency	Electrification of Heating and Vehicles	Electricity Supply (SWITCH)	2050 Carbon Cap for Electricity [% reduction from 1990 Emission Levels]	In-State Biomass	SWITCH biomass supply curve [Mdt]	Biomass for fuel [Mdt]	Instate Biofuel [Bgge]	Imported biofuel [Bgge]	California Energy Emissions [MMtCO2eq]	Emissions With Nominal Behavior Savings [MMtCO2 eq]	Emissions With High Behavior Savings [MMtCO2 eq]
Frozen Efficiency	Frozen Efficiency	BAU	Without carbon cap	N/A	BAU					671	636	605
Frozen Efficiency + Electricity Cap	Frozen Efficiency	BAU	With carbon cap		BAU					512	479	450
Base case	Tech. Potential	Median (Base case level)	Base case	80%	Low, for liquid fuel	0	35	2.8	0.93	130	119	112
High Nuclear			Inexpensive nuclear		Low, for liquid fuel					130	119	112
High CCS			Inexpensive CCS		Low, for liquid fuel					130	119	112
No CCS or New Nuclear			No CCS or New Nuclear	80%	Low, for liquid fuel					130	119	112
No CCS			All CCS excluded		Low, for liquid fuel					130	119	112
High Solar and Wind			Inexpensive solar and Wind		Low, for liquid fuel					130	119	112
Expensive Photo-voltaics			Expensive Photo-voltaics		Low, for liquid fuel					130	119	112
Biomass CCS			Biomass CCS	100%	Low, for electricity	23	12	1.0	0.3	124	113	106
Biomass CCS + Hi in-state biomass			Biomass CCS	100%	High, for electricity and liquid fuel	23	71	5.7	1.9	91	83	79
High in-state biofuels			Base case	80%	High, for liquid fuel	0	94	7.5	2.5	97	88	82
Hi in-state & High imported biofuels					High in-state + High imports, for liquid fuel		94	7.5	7.5	74	66	62
High Electrification		High	Base case	80%	Low, for liquid fuel	0	35	2.8	0.9	99	90	84
High Electrification & High in-state biofuels		High			High, for liquid fuel		94	7.5	2.5	71	63	59

Table 12-4. *Summary of 2050 California GHG emissions for various modeled scenarios. All non-reference case scenarios assume technical potential energy efficiency, and electrification of heating and vehicles.   Shaded boxes represent scenarios which meet the 80MMt target.*
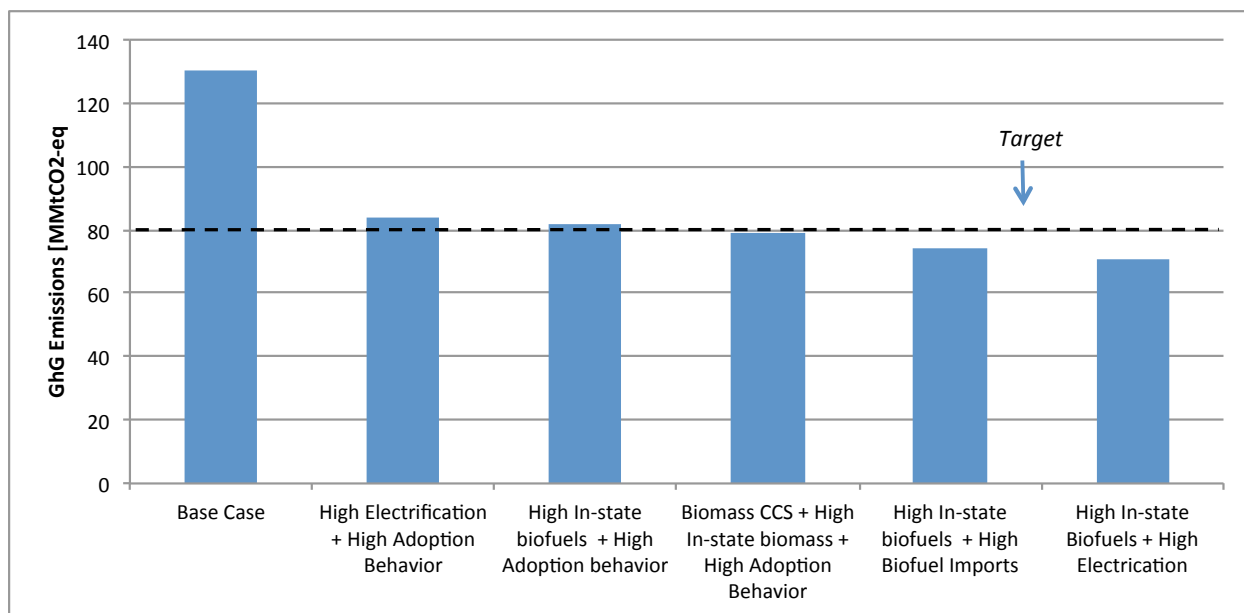
Figure 12-5. *2050 California GHG emissions for base case variants. Several scenarios meet or are very close to the 2050 target.*

The reference (frozen efficiency) case has 671MMt emission in 2050. Applying an 80% carbon cap to the electricity sector reduces this to 512 MMt (the "clean electricity only" bar in Figure 12-4). The base case and electricity system variants have final overall emissions of 130MMt. (Fuller description of the electricity system cases is provided in Section 10). Here we note again that an external carbon cap was set on the electricity system and there is no feedback between the electricity sector and the non-electricity sector (e.g. no impact to industry or manufacturing energy demand as a function of electricity supply mix).

Moving from low in-state biofuel supply in the base case to high in-state supply reduces overall emissions from 130MMt to 97 MMt while moving from the base case to the high electrification case reduces emissions to 99MMt. Similar impacts of about 25% emissions reduction are observed for high in-state bio fuels or high electrification, versus the base case. It would be thus interesting to study the cost impacts of each variant to maximize benefit/cost impact to the state. We did not consider a case of even higher energy efficiency that would take into account out of paradigm technologies (e.g. non-compressive HVAC systems), system integration and integrated design approaches. Future work will also explore further cases of carbon neutrality or net negative emissions in the electricity sector.

Two cases are found to meet the 80 MMt target without any additional behavior change savings: the high in-state biofuels case with either high imported biofuels or with high electrification. Adding high adoption behavior can reduce energy emissions to around 60MMt or about 20MMt below the target. However, in the former case, imported biofuels would exceed the 25% limit of overall supply (Executive order S-06-06, 2006) in 2050 and the latter case would require almost a

146

complete phase-out of conventional internal combustion vehicles by 2050 and is probably best viewed as an illustrative bounding case for maximal EV penetration.

12.4   High In-state Biofuels Case

We consider the high in-state biofuels case in greater detail since this case has base case efficiency and electrification and meets the goal of 75% in-state produced biofuels.   Moving from low in-state biofuels to high in-state biofuels reduces overall emission from 130MMT to 97MMt CO_2eq in 2050. The overall modeled GHG trend is show in Figure 12-6 showing a sharp reduction in emissions across most sectors. In particular, transportation sector emissions are reduced from vehicle electrification and biofuels and the oil and gas industry is reduced by about two-thirds. The electricity sector is also reduced about 80% from current levels due to shifting to clean power supply sources.   The black solid line represents total emissions after assuming high behavior change adoption replacing fossil fuels and is seen to be within a few percent of the 2050 target at 82 MMt.   Referring to Table 12-4, it can be seen that some combination of incrementally higher electrification, imported biofuels (albeit above the 25% import target) or behavior savings can further reduce emissions for this case to meet the 2050 target. If future policy or carbon economics move the state to a regime where behavior savings translate directly into fossil fuel savings, then high in-state biofuels with nominal behavior savings are sufficient to meet the target (76 MMt). A breakdown of all sectors is provided in Table 12-5.
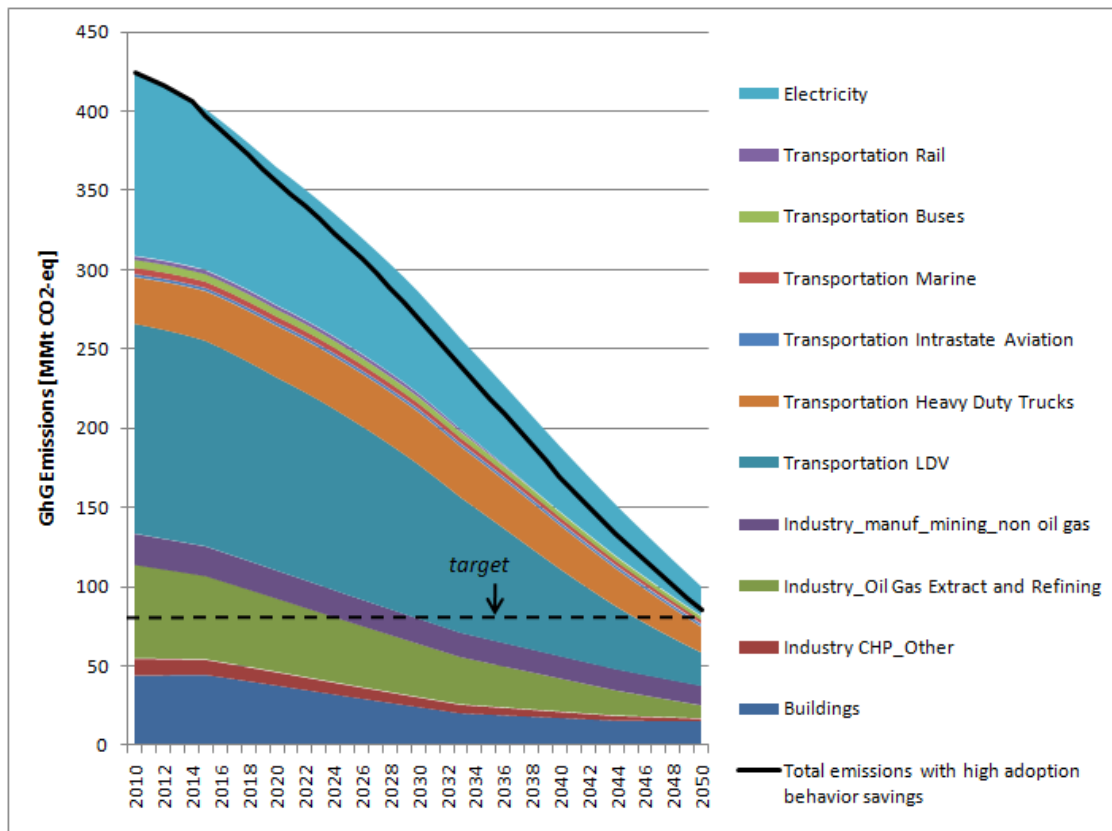
Figure 12-6. *High in-state biofuels case. The solid line represents total emissions after high behavior savings and is just above 80 MMt (dashed line).*

Sector	2008 CARB Emissions [MMtCO2eq]	2050 Reference Case	2050 Base Case [MMtCO2eq]	2050 Base Case with High In-state Biofuels [MMtCO2eq]	2050 Base Case with High In-state Biofuels and High Behavior Adoption [MMtCO2eq]
Transport	175.0	313	69	42	35
Power	116.4	171	18	18	17
Industry	92.7	121	28	22	16
Commercial/residential	43.1	66	14	14	14
Total, Energy emissions	427	671	130	97	82
Percentage from 2050 energy emissions target (80 MMt CO2-eq)			63%	21%	3%
Landfills	6.7	16	2	2	2
High GWP	15.7	71	38	38	38
Agriculture/forestry	28.3	52	27	27	27
Total, Non-Energy emissions	50.6	139	67	67	67
Total, Energy and non-energy emissions	477.8	810	197	164	149
Percentage change vs 2050 target, 85 MMt CO2-eq			131%	93%	75%

Table 12-5. *California GHG emissions in 2008 (CARB 2010B) and for 2050 high in-state biofuels cases.*

Table 12-5 illustrates the difficulty of meeting non-energy emissions. Non-energy emissions in 2050 are projected to be reduced from 139 MMt to 67 MMt with known technical potential measures but this far exceeds the 2050 target of 80% reduction from 1990 levels (5.4 MMt). Even if landfill and agriculture/forestry emissions were brought to zero through maximal diversion of solid wastes, methane capture and aggressive afforestation, high GWP would have to be reduced a further 80% to meet the 2050 target.

We further analyze 2050 scenarios by disaggregating the overall carbon emissions reduction into energy demand reduction and energy intensity (CO_2 per unit of energy). This is shown in Table 12-6 for fuels and electricity for three cases: (a) base case; (b) base case plus high in state biofuels; and (c) base case with high in-state biofuels and high behavior change adoption (where fossil fuel demand is reduced at the margin). In the base case, fuel demand is sharply reduced from three factors: energy efficiency, fuel switching and oil and gas industry replacement. Concurrently, electricity is dramatically cleaner with 90% reduction in carbon intensity [grams CO2-eq/kWh]. Moving from the base case to high in-state biofuels and high behavior adoption we observe that the fuel intensity [grams CO2-eq/gge] becomes successively lower as the relative fraction of biofuels to gasoline increases. These tables illustrate the key strategy of these scenarios: first reducing energy demand in fuels through efficiency and fuel switching and then to combine this with sharply reduced electricity carbon intensity.

GHG Source	2050 Reference Emissions [MMtCO2eq]	2050 Base Case		Emissions after energy savings and carbon intensity reduction [MMtCO2eq]
		Energy Savings	Carbon Intensity Reduction	
Fuels	500	74%	14%	112
Electricity	171	-6%	90%	18
Total	671			130

(a)

GHG Source	2050 Reference Emissions [MMtCO2eq]	2050 Base Case + High In-state Biofuels		Emissions after energy savings and carbon intensity reduction [MMtCO2eq]
		Energy Savings	Carbon Intensity Reduction	
Fuels	500	75%	37%	79
Electricity	171	-7%	90%	18
Total	671			97

(b)

GHG Source	2050 Reference Emissions [MMtCO2eq]	2050 Base Case + High In-state Biofuels + High Behavior Savings		Emissions after energy savings and carbon intensity reduction [MMtCO2eq]
		Energy Savings	Carbon Intensity Reduction	
Fuels	500	80%	37%	65
Electricity	171	2%	90%	17
Total	671			82

(c)

Table 12-6. *Energy intensity decomposition of 2050 emissions reduction for fuels and electricity for (a) base case; (b) high in state biofuels; and (c) high in-state biofuels and high behavior change adoption. [Note that a negative energy savings percentage denotes an increase in energy demand].*

An evolution of the energy demand and overall GHG are show in Figure 12-7 and 12-8. Overall energy demand evolution is shown in Figure 12-7 showing the additive impact of various strategies and separating out fuel and electricity demand. Energy efficiency savings yield 46% savings for fuel and 33% for electricity. Electrification of vehicles and heating increase electricity demand to 7% higher than the reference case level but fuel consumption is decreased by one-half. Note that the reduction of the oil and gas industry is included in this transition because of the high rate of vehicle electrification and reduction in fossil fuel demand. Adding base case level biofuels does not shift overall energy levels appreciably, while the case of high in-state biofuels and high behavior adoption further reduces both fuel and electricity demand.

Figure 12-8 shows energy related greenhouse gas emissions in 2050 for energy demand levels including the transition to cleaner electricity. Here, electricity emissions are sharply curtailed from the reference case figure although overall electricity demand is similar. Fuel emissions are seen to

take three large downward steps: from energy efficiency, then fuel switching, and then finally in moving to a larger in-state biofuel supply and including high adoption behavior savings. In moving from clean electricity to electrification, an estimated 128 MMt-CO2eq are saved. Of this about 56% is due to transport (72MMt), 21% from industry (27 MMt) and 23% from building electrification (29 MMt).
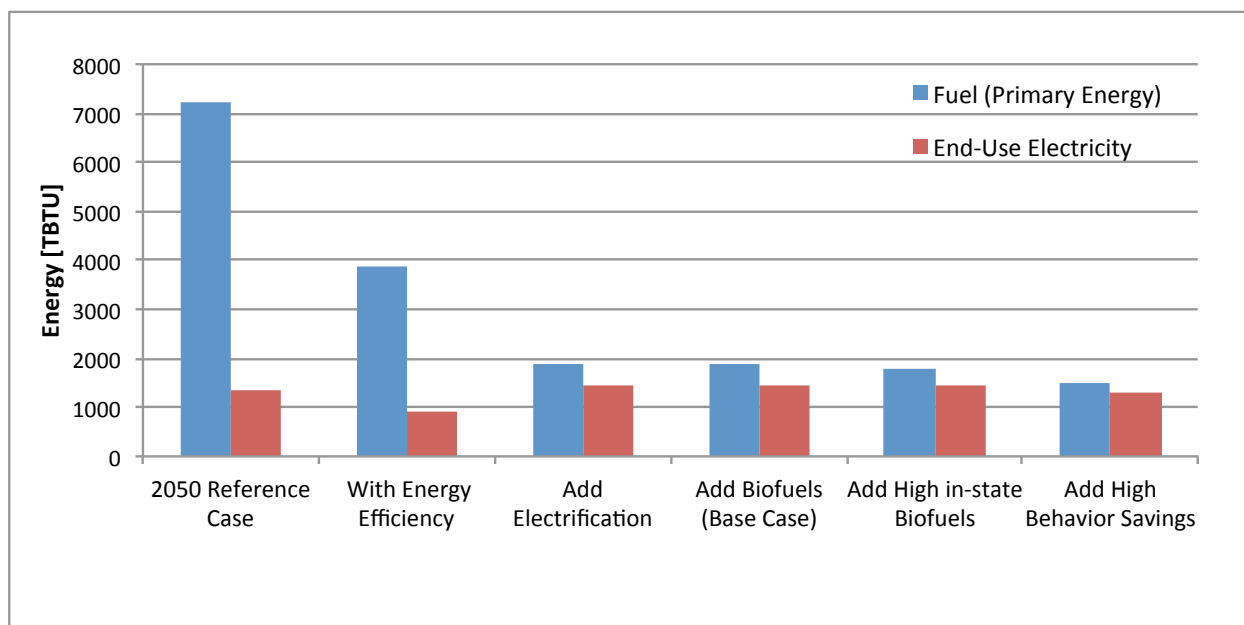
Figure 12-7. Energy system demand[18] evolution for 2050 base case and with high in-state biofuels and high behavior

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[18] End use electricity is shown since primary energy demand for electricity in 2050 will be highly dependent on the actual mix of generation technologies. For reference, the approximate ratio of source to site energy is 3:1 for current grid-based electricity, and if the current mix of generation technologies does not change, primary energy would be three times the end use electricity demand shown here.
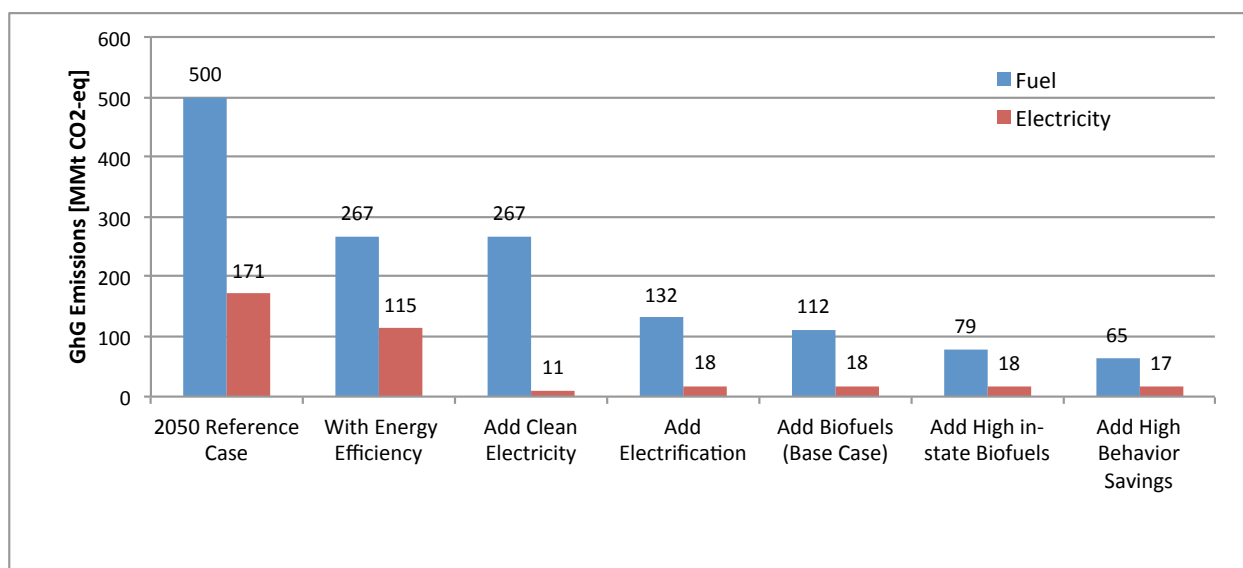
Figure 12-8. Energy related GHG emission evolution for 2050 including the transition to clean electricity.

12.5 Biomass CCS Cases

The biomass CCS achieves carbon neutrality (zero emissions) in the electricity sector but with slightly lower decarbonization in the transportation sector since less biomass is available for biofuels. With low in-state biomass, overall energy emissions are 124MMT. Adding high in-state biomass (23 Mdt for electricity and 71Mdt for in-state biofuel production) reduces this to 91 MMt. Adding high adoption behavior savings further reduces emissions to 79MMt, meeting the 2050 target. Overall breakdown of emissions and energy savings/ carbon intensity reduction tables are shown in Tables 12-7 and 12-8. Comparing Table 12-8 to Table 12-6, we see that the electricity sector is decarbonized but the fuels sector has higher carbon intensity since less biomass is available for biofuels.

A comparison of the biomass CCS case with the base case provides a comparison of the carbon reduction merits of directing biomass to power with carbon capture versus liquid fuel production. In the former case 23Mdt of biomass are reserved for electricity with a carbon neutral cap while in the latter case, these 23Mdt are directed to biofuel production and there is an 80% carbon cap for electricity. We find that biomass CCS has 124 MMt emissions versus the base case at 130 MMt. However, this is not a matched comparison, since the base case has more imported biofuels. Correcting for this, biomass CCS has about 10 MMt or about 8% lower overall energy emissions than the high biofuels case. We also note that across the WECC, only about 75% of available biomass was used for biomass CCS power production. Thus biomass CCS appears to offer an efficacious technical path for lower carbon emissions, but overall emissions in such a comparison will be of course highly dependent on the set of assumptions regarding each pathway, such as the emissions factors for biofuel production, the power conversion efficiency of biomass CCS plants, the

suitability of different feedstocks versus pathway, etc. Moreover, economics of production and distribution, market incentives and overall policy frameworks are expected to strongly influence future biomass production and utilization patterns.

We did not model net negative carbon emissions biomass CCS scenarios for the electricity sector nor did we model non-biomass CCS scenarios with greater than 80% GHG reduction from 1990 levels. These will be a priority item for future work, especially when coupled with "technical potential" biomass estimates for the entire WECC. These scenarios of lower electricity emissions to net negative emissions offer the prospect of providing more room for other sectors which are more difficult to decarbonize as well as the opportunity to further investigate the optimal disposition of biomass supply.

Sector	2008 CARB Emissions [MMtCO2eq]	2050 BAU case	2050 Biomass CCS Case [MMtCO2eq]	2050 Biomass Case with High In-state Biofuels [MMtCO2eq]	2050 Biomass CCS Case with High In-state Biofuels and High Behavior Adoption [MMtCO2eq]
Transport	175.0	313	81	53	45
Power	116.4	171	0	0	0
Industry	92.7	121	29	23	19
Commercial/residential	43.1	66	15	15	15
Total, Energy emissions	427	671	124	91	79
Percentage from 2050 energy emissions target (80 MMt CO2-eq)			56%	14%	-1%
Landfills	6.7	16	2	2	2
High GWP	15.7	71	38	38	38
Agriculture/forestry	28.3	52	27	27	27
Total, Non-Energy emissions	50.6	139	67	67	67
Total, Energy and non-energy emissions	477.8	810	191	157	146
Percentage change vs 2050 target, 85 MMt CO2-eq			124%	85%	72%

Table 12-7. California GHG emissions in 2008 and for 2050 biomass CCS with high in-state biofuels cases.

GhG Source	2050 Reference Emissions [MMtCO2eq]	2050 Biomass + CCS		Emissions after energy savings and carbon intensity reduction [MMtCO2eq]
		Energy Savings	Carbon Intensity Reduction	
Fuels	500	74%	6%	125
Electricity	171	-6%	100%	0
Total	671			125

(a)

GHG Source	2050 Reference Emissions [MMtCO2eq]	2050 Biomass CCS + High In-state Biofuels		Emissions after energy savings and carbon intensity reduction [MMtCO2eq]
		Energy Savings	Carbon Intensity Reduction	
Fuels	500	75%	28%	91
Electricity	171	-7%	100%	0
Total	671			91

(b)

GHG Source	2050 Reference Emissions [MMtCO2eq]	2050 Base Case + High In-state Biofuels + High Behavior Savings		Emissions after energy savings and carbon intensity reduction [MMtCO2eq]
		Energy Savings	Carbon Intensity Reduction	
Fuels	500	78%	28%	79
Electricity	171	2%	100%	0
Total	671			79

(c)

Table 12-8. Energy intensity decomposition of 2050 emissions reduction for fuels and electricity for (a) biomass CCS case; (b) biomass CCS with high in state biofuels; and (c) biomass CCS high in-state biofuels and high behavior change adoption.   [Note that a negative energy savings percentage denotes an increase in energy demand].

12.6   Behavior Savings

Behavior change savings are between 11 and 18 MMt for the base case for low and high adoption rates or 8-14% savings. Across the scenarios, behavior savings range from 8% to 17%. Savings are also calculated assuming that behavior savings translated directly into fossil fuel savings. In this case, savings become 21MMt and 39MMt (16% and 30% savings) respectively for the base case.

One can also ask how much behavior change savings would be required in a given scenario to meet the target. For example, the base case and high biofuel supply cases have overall emissions of

130MMt and 97MMt implying that behavior change savings of 38% and 18%, respectively, would be required to meet the target.

Behavior savings with our estimated high adoption rates allow several cases to either meet the target of come very close to meeting it: the biomass CCS, high in-state biofuels, and high electrification cases. As noted in the behavior section above much of the behavior savings are from reduced liquid fuel consumption from transportation measures and savings are reduced as the fuel system becomes cleaner.

13.   INCREMENTAL COST ESTIMATES TO 2020

The estimate of total incremental cost associated with achieving technical potential savings in the buildings sector over to 2020 is $57.8 billion ($2006 dollars). This estimate is based the cost analysis of over 300 individual measures conducted in the 2008 Itron potential update study using measure cost data from the CPUC's 2004-2005 *Database for Energy Efficient Resources*.

It should be noted that these total incremental costs are associated with measures applicable to existing buildings and do not reflect any bottom-up estimates of total incremental costs associated with technical potential savings in the new construction segment. The reason for excluding cost estimates associated with the new construction segment is that current incremental cost estimates for zero net energy homes and buildings are severely limited and difficult to scale to the general population with a reasonable amount of certainty.

Because the incremental costs associated with the assumed penetration of zero net energy buildings are excluded, one would thus expect our incremental cost estimate to systematically underestimate the actual costs associated with total technical potential, since net zero energy homes and buildings account for approximately 12% of total technical potential savings in 2020. However, Figures 4-1 and 4-2 in section 4.5 show that the "max-EE" scenario assumes that only 70-80% of total technical potential is actually realized by 2020 through utility rebate programs. In our judgment, the exclusion of the costs associated with net zero energy homes and buildings is roughly balanced by the inclusion of costs associated with technical potential savings that have yet to occur by 2020 in the max-EE scenario.

Incremental cost estimates for new construction are not well characterized at this point though an active new area of research. Case studies are typically performed under idealized house conditions and actual costs are expected to vary by location and climate zone-dependent measures.   Some researchers argue that best practice costs are equivalent to current new housing construction but while this may be true in some cases, actual building performance for "net zero energy homes" can vary widely, so that actual costs per unit energy savings need careful assessment.

Incremental costs for building electrification are estimated to be $3.2 billion through 2020 from electrification of residential space heating and residential and commercial water heating (see Building chapter adoption rates). This is a relatively smaller number than the other building efficiency costs since the bulk of building electrification occurs after 2020.

INCREMENTAL COSTS FOR TRANSPORTATION

This section provides rough estimates of the incremental costs associated with adopting advanced and electric-drive vehicles over and above conventional vehicles out to 2020. This is an area that requires significantly more research, especially in non-LDV transportation subsectors where there is often little published data on costs for electrification or other options to increase efficiency. Additional capital costs for the purchase of advanced vehicles will be balanced out, to some extent, by the greater fuel efficiency and lower fuel costs associated with advanced vehicles. In addition, the switch from petroleum based fuels to electricity as a fuel can also lead to further reductions in fuel expenditures. The extent to which the use of advanced vehicles pay for this additional capital

expenditure on a purely economic basis will depend upon the cost of technology, future fuel prices, the analysis time period, and other economic assumptions, all of which are uncertain.

LIGHT-DUTY VEHICLES

This subsector has been studied in sufficient detail that the costs for various options to increase efficiency and electrify cars and trucks is well characterized. Kromer (2007) provides costs estimates for HEVs, PHEVs and BEVs in 2030 ($10,200 for a BEV and $3000 for a PHEV10), while (NRC 2011) provides estimates for current costs ($29,400 for a BEV and $7700 for a PHEV10) which are significantly higher. Costs are assumed to decline linearly as a function of time.

Based upon the sales of these vehicles advanced vehicles in California in the scenario, the total incremental cost of purchasing HEVs, PHEVs and BEVs is around $10 billion over the 11 year period 2010 to 2020, which works out to be a premium of around $3000 for each of the 3.3 million advanced vehicles sold in this time period (the average incremental cost of BEVs is around $14,900, $4800 for PHEVs and $2900 for HEVs).

Other subsectors

Less information is available in the literature regarding the incremental costs associated with the advanced energy saving technologies in other transportation subsectors. Some analyses provide some data on the cost effectiveness of specific technologies in a given subsector but it becomes difficult to apply these costs in a consistent manner across the board.

The National Research Council (NRC 2010B) provides some estimates for the incremental cost of efficient heavy duty trucks (tractor trailer) that reduces fuel consumption 51% at $85,000, which would require only a 3 year payback period at $2.85/gallon of diesel and smaller trucks with an incremental costs of $43,000. Because these options are not expected to be fully implemented in the fleet by 2020, a fraction of these costs are applied proportionally to all trucks sold and results in cumulative incremental cost of around $7 billion dollars. Hybrid and electric buses are expected to yield an incremental cost of around $400 million.

The full complement of aircraft efficiency options (including engine upgrades and aerodynamic improvements) is expected to have an incremental cost of around $9 million per airplane, which can reduce aircraft fuel consumption per passenger mile by 50% by 2035. However, by 2020, new aircraft will not achieve this level of efficiency improvement and the incremental cost will not be as high. It is estimated that approximately 2800 new aircraft will be needed to fly California-related flights between 2010 to 2020 at an average incremental cost of $2.4 million for a total incremental cost of $6.8 billion.

Several sources indicate that the primary incremental cost of electrified rail is the cost of electrifying the track. The cost of an electric locomotive is not expected to be significantly different than a diesel-electric locomotive. Based upon estimates of around $2 million to electrify one mile of track, electrifying California's 7700 miles of rail would cost about $15 billion. Costs to 2020 are estimated to be about 20% of this or $3 billion.

Unfortunately there is little information about the cost of marine efficiency improvements that could be attained from the literature. No estimate for marine shipping is provided.

Industry and Biofuels

For the industry sector in the short term, McKinsey estimates 18% energy savings in 2020 with a $113 billion net present value investment (McKinsey 2009) and a benefit to cost ratio of 4:1, indicating the sub-optimality of current industry operations from an energy standpoint. These energy savings are very similar to the base case industry savings in 2020 in this report. We hence assume that this national cost estimate translates to about $10 billion investment for the state of California, with a 9% fraction of national industry-sector energy based on 2008 industry data. Note however, that this is not an incremental cost but an overall investment so this may represents an upper limit for this sector.

Biofuels are assumed to not add significantly to 2020 costs since we assume a slow ramp up in the state until 2030 for the base case and in-state biofuel production does not exceed the biofuel production associated with the 2020 LFCS target.

Electricity

Electricity system costs are estimated to be $8 billion lower for the base case to 2020 versus the frozen efficiency case with a 33% RPS requirement for both cases. This savings results from lower overall demand in the base case (244,700GWh) compared to the frozen efficiency case (277,600 GWh) and hence the need to build less renewable generation sources. This number will clearly be sensitive to a number of factors including the mix of renewable energy, the cost of renewable generation sources and overall demand evolution. In this analysis, we do not include the feedback effect of lower fuel and electricity demands on prices.

Energy cost savings are highly dependent on oil prices and to a lesser extent natural gas prices which can of course can be highly volatile and difficult to predict. As SWITCH does not currently output the projected price of power for the state of California alone (the calculated price of power is a WECC-wide value), we use a recent CPUC report to estimate the dollar value of electricity savings. These savings are based on saving 33,000 GWh relative to the reference case in 2020 and assuming an increase in electricity prices from current 13.8 cents/kWh to 15.4 cents/kWh in 2020 (CPUC 2009]. Industry and building fuel savings reach 4.4 billion therms in 2020 and natural gas prices are assumed to rise from current $.68 per therm to $.75 per therm [AEO2011]. Gasoline prices are assumed to rise 23% from current prices following the AEO2011 report. With 3.4 billion gallons of gasoline saved in the 2020 base case, this translates to almost $60 billion in savings.

Sector	Incremental Investment Costs [$2010 billion dollars]
Buildings	65.0
Transport	27.2
Light duty vehicles	10.0
Trucks	7.0
Air	6.8
Marine	Not available
Bus	0.4
Rail	3.0
Industry	14.8
Electricity	-7.7
Total Incremental investment costs	99.3

(a)

Energy Type	Energy Cost Savings [$2010 billion dollars]
Natural Gas	14.2
Gasoline	59.4
Electricity	26.1
Total energy cost savings	99.8
Total Energy cost savings less Incremental investment costs	0.5

(b)

Table 13-1. Total estimated incremental investment costs and energy cost savings for the base case to 2020 (undiscounted).

Total estimated incremental investment costs and energy cost savings for the base case to 2020 is shown in Table 13-1.   Overall costs are essentially neutral with overall costs and savings about $100 billion.   This cost calculation does not include life-cycle cost savings from energy efficiency measures nor does it include health and environmental impacts, both of which would provide further financial benefits to the base case.   The calculation also does not discount future costs or savings, which are highly sensitive to the assumed discount rate, with no universally agreed-upon default value. Moreover, a complete accounting of costs and savings would need to include savings from investments that continue to accrue beyond 2020.

14. AREAS FOR FUTURE WORK

General areas

More economic considerations especially in the near term to 2020-2025, are an area for future work. For example, cost analysis and resource requirement scoping for biomass and biofuel supply ramp up and cost/benefit analysis of electrified heating would be helpful inputs for future policy discussions. More realism could be added with more cross sector interactions and feedback, for example a fuller accounting of how changes in the energy supply or widespread deployment of energy efficiency impact the industry sector.

Sensitivity to base case model assumptions (e.g. population, industry GDP growth, per-capita vehicle miles driven) would add insight and highlight critical sensitivities but was beyond the scope of this study.

Energy Efficiency

For the most part, "in-paradigm", commercially available technologies were considered for technical potential energy efficiency savings. The following energy efficiency approaches were not considered in detail: "out-of-paradigm" but commercially available technology such as non-compressive HVAC systems; system integration concepts (e.g. integrated residential/commercial systems with solar PV and dedicated direct current end use loads); and integrated design techniques. It would be valuable to quantify the impacts of these approaches in the building, industry, and transportation sectors.

Electricity System and Electrification

Our 2050 base case electricity system utilizes invariant vehicle and building electrification load profiles, thereby causing the total system load profile to have sharp peaks during hours in the evening. A further optimized electricity system could be achieved by load shifting and demand response to reduce peak load and increase load factor, or for example by "smart grid" technologies that could sense supply and adjust demand rather than the converse that is in current practice. Thus it would be valuable to study demand response as a resource and to try to characterize a cost supply curve for such a resource.

Further characterization of load balancing requirements and sensitivities as a function of intermittent supply resource penetration should be pursued. This topic is closely related to the demand response item above.

As discussed in the text, we plan to model electricity scenarios with carbon emissions capped at lower values for both the biomass CCS and the non-biomass CCS cases. This could allow other sectors such as transportation and non-energy emissions to emit more GHG and still meet the economy-wide carbon cap. Such an extension may also provide some rough cost guidance for the tradeoffs involved investing in cleaner and potentially carbon-negative electricity systems to meet overall emissions targets versus other options such as investing in behavior change or importing biofuels.

Our base case includes electrification of vehicles and heat. Clearly carbon reduction from electrification only follows if the electricity system has low carbon emissions. Our endpoint in 2050 is a much cleaner electricity system with a large emissions reduction from fuel switching to electricity. While SWITCH is a cost optimization program for minimizing overall system cost given a set of electricity demands and a constraint on carbon, our modeling does not simultaneously optimize greenhouse gases and the rate of electrification. Such an optimization may be possible to model, but difficult to implement in practice.

In general, electricity reliability may be a concern with a larger fraction of energy service provided by electricity and with a greater fraction of intermittent renewable sources in the electricity. More study should be directed to addressing this concern in terms of system characterization, system stability, optimization of backup and load balancing capacity, and system sensitivities. Pursuing and achieving high degrees of energy efficiency is helpful to keep overall statewide demand similar to reference levels. Electricity is about 37% of total state primary energy in 2008 and in the 2050 reference case, increasing to about two thirds of primary energy in the 2050 base case. As reference, electricity in France, with its heavy reliance on nuclear power, constituted about 55% of primary energy in 2004. While California may not move to such a high reliance on nuclear power in the future, this suggests that much higher levels of electricity penetration are possible without a significant impact to overall reliability.

The greater need for refrigerants such as HFCs in future energy systems with high penetration of heat pump based systems should be better understood in light of the requirement for sharply reduced high GWP emissions. It would also be interesting to compare different technology implementations of building heating for cost and overall energy and GHG savings, for example heat pump based systems versus district heating or hydronic systems for new construction.

From a policy standpoint, the main gap in the portfolio of state energy policy is a policy framework for electrified heating in buildings and industry (see Appendix – California Energy Policies). While there are periodic appliance and equipment rebate programs for electric hot water heating systems at the residential (PG&E 2011) and commercial level (DOE 2010), a policy framework should be developed in the near term to enable the state to meet the electrification targets outlined here since this is a long lead time item.

Finally, a detailed accounting of each WECC region's projected electricity demand in similar detail to California was not within the scope of this work and is an area for more detailed study in the future.

Biomass/ Biofuels

More study of biomass supply curves and economics for agricultural residues and MSW beyond 2020-2030 would be helpful. A more detailed treatment of biomass disposition (electric power versus liquid fuel) would include technical, cost, policy and geographic sensitivities to help determine the best use of this resource. The land and resource requirements to support production of biomass at technical potential production levels should be investigated and the interaction with wider scale afforestation for carbon sequestration should be studied.

Behavior

A policy framework for first halting current behavior related trends in energy consumption and second, reversing them is an area for further development.   Best practices and learning from abroad can inform policies supportive of long term behavior change, ideally tested with pilot programs before implementation.   Further quantification of baseline behavior as it pertains to energy consumption and segmentation analysis of population subgroups across geography, demographics, and cultures would be helpful to develop better adoption rate models.

High GWP Sources

More study in the control, monitoring and abatement of high GWP sources is needed as high GWP sources become a large fraction of emissions in 2050 if current trends continue unabated.   Current growth rates are 4-5% per year in emissions and the CEC2005 study has only a 25% technical potential reduction by 2020.

Other

We did not pursue aggressive penetration of CHP in industry and other sectors such as commercial buildings since we try to minimize fuel usage across sectors, unlike the AEO2011 which includes greater industry CHP from previous year forecasts. We did not study the optimal mix of CHP, district heating, and electrification and the quantification of this and policy implications are areas for future work.

15. CONCLUSIONS AND SUMMARY

In this report, we have shown that it is possible to meet the 2050 GHG target for energy emissions with a portfolio of approaches and with largely existing technologies. The base case of technical potential energy efficiency, clean electricity, electrification of vehicles and heating, low carbon biofuels achieves a 67% reduction from 1990 levels.

Reaching the 80% target can be achieved from some combination of higher biomass supply, higher electrification, and behavior change. The following cases build upon the base case and meet the 80% target: biomass CCS with high in-state biomass and high adoption behavior savings, high in-state biofuels and high biofuel imports, and high in-state biofuels and high electrification. Two cases which achieve savings very close to the 80% target are high in-state biofuels and high adoption behavior, and high electrification with high adoption behavior.

Aggressive energy efficiency reduces overall energy (fuel plus end use electricity) demand by about 43% in 2050, and the remaining fuel demands are significantly decarbonized by aggressively electrifying vehicles and heating and cleaning up the electricity supply. Production of in-state low carbon biofuels further lowers emissions. We also demonstrated that some biomass supply can be directed to power production with carbon capture and storage to completely decarbonizes the electricity sector, and that this approach can also give slightly lower overall carbon reductions to the base case where all emissions are directed to biofuels.

Although much of this transition can occur with mostly commercially available products and existing technology, development is needed in many areas such as electric vehicle batteries, carbon capture and storage, electrified process heating systems and advanced biofuels. Overall incremental cost to 2020 is estimated neutral to slightly lower than the reference case with frozen efficiency, not counting LCC cost savings of energy efficiency measures. Electricity to 2050 is projected to be within 15% of today's cost in 2050. This suggests that, in addition to continuing technology development of generation technologies, large area planning and electricity system optimization exemplified in SWITCH are essential to containing electricity costs.

The main obstacle to meeting 2050 targets does not appear to be technological but rather the lack of a policy and regulatory framework to support these measures to the degree required. The timing and implementation schedules for energy saving measures are important to consider since equipment and housing units have long lifetimes, and "lock-in" of inefficient systems may make it difficult to impossible to meet the goal. Many energy efficiency measures have market penetration and adoption rates which are lower than what are needed Existing policies such as 33% RPS, LCFS and utility rebate programs can be built upon and strengthened. One area is highlighted as a "paradigm change" from current state energy policy: electrification policy and technology development and deployment infrastructure is lacking and is needed to meet aggressive electrification goals in building and industry heat.

Finally, long behavior change is highlighted as an opportunity to save up to 17% of GHG emissions in 2050, and this option is worthy of greater study and testing as a potentially cost competitive abatement option compared to purely technological solutions.

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APPENDIX 1. LIST OF CALIFORNIA ENERGY POLICIES[19]

Category	Policy	Year	Description	Building Efficiency	Industry Efficiency	Transport Efficiency	Clean Electricity	Building Electrification	Industry Electrification	Transport Electrification	Biofuels	Long Term Behavior
Cross sector	Executive Order S-03-05	2005	Targets an economy-wide reduction in greenhouse gas emissions 80% below 1990 levels by 2050	x	x	x	x				x	
Cross sector	AB 32	2006	Targets an economy-wide limit on greenhouse gas emissions to 1990 levels by 2020. California Air Resources Board to adopt regulations and implement market mechanisms to achieve the target.	x	x	x	x				x	
Cross sector	Cap and Trade	2006	Enactment of a cap and trade system for large industrial CO2 sources including in-state electricity generation 2012-2014; expanding to upstram treatment of fuel combustion 2015-2020 (small industrial, residential, commercial, transportation)	x	x	x	x			x		x
Energy Efficiency	"California Long-term Energy Efficiency Strategic Plan" (CPUC)	2008	Energy efficiency programs and building standards including Zero net energy buildings	x	x	x	x					
Clean electricity	Million solar roofs initiative (SB1)	2004	Requires that the state provide incentives to help install 3,000 MW of rooftop solar PV by 2017				x					
Clean electricity	SB 1368 Emissions Performance Standard	2006	Long-term investments in baseload generation by the state's publicly owned utilities to power plants must meet an emissions performance standard equivalent to a natural gas-fired combined-cycle plant.				x					

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[19] For a comprehensive treatment of California policies regarding the 2009 Federal Stimulus, see California Energy Commission, 2011. 2010 Integrated Energy Policy Report Update. Publication Number: CEC-100-2010-001-CMF.

Category	Policy	Year	Description	Building Efficiency	Industry Efficiency	Transport Efficiency	Clean Electricity	Building Electrification	Building Electrification	Transport Electrification	Biofuels	Long Term Behavior
Clean electricity	Renewable Portfolio Standard (SB 1078)	2006	Requires 20% of electricity generation to come from renewable resources by 2010.				x					
Clean electricity	Executive Order S-21-09		Sets a 33% renewable electricity target by 2020.				x					
Clean electricity	Carbon Capture and Sequestration		California is a major participant in the West Coast Regional Carbon Sequestration Partnership (WESTCARB). The partnership researchs and tests capture and sequestration(CCS).									
Clean energy	Solar Water Heating AB1470	2007	Incentive program with the goal of installing 200,000 solar hot water heating systems in California by 2017.	x								
Other Transport	Port Electrification	2007	California 2007 State Implementation Plan (SIP) requires ship electrification at ports			x				x		
Other Transport	Prop 1A, High speed rail	2008	California Proposition 1A passed in November 2008 with the target of an electric, high-speed rail link between SanFrancisco and Los Angeles by 2030.			x						
Transport Fuels	AB 2076	2000	Requires state agencies to set goals for reducing petroleum consumption in California.			x				x	x	
Transport Fuels	AB 1007	2005	Establishes a statewide alternative fuels plan and sets a 15% reduction goal in petroleum consumption in California by 2020.			x				x	x	

173

Category	Policy	Year	Description	Building Efficiency	Industry Efficiency	Transport Efficiency	Clean Electricity	Building Electrification	Industry Electrification	Transport Electrification	Biofuels	Long Term Behavior
Transport Fuels	Executive Order S-06-06	2006	Sets targets for bioenergy. 40% of biofuels consumed in California to be produced in California by 2020 (75% by 2050).								x	
Transport Fuels	AB109	2008	Authorizes California Energy Commission to develop and deploy renewable fuels and advanced transportation technologies to help attain the states climate change policies			x				x	x	
Transport Fuels	Low Carbon Fuel standard	2009	Sets performance standards for reducing transportation fuel carbon intensity by 10% in 2020 and recognizes electricity as a low-carbon fuel, taking into account lifecycle emissions of transportation fuels								x	
Transport/ Electricity	SB 17	2009	Requires the California Public Utilities Commission to develop a smart grid implementation plan that integrates the storage technologies of plug-in hybrid vehicles.			x				x		
Transport/ Electricity	SB 626	2009	Requires the California Public Utilities Commission to develop a regulatory framework to overcome barriers to widespread use of PEVs in the state, e.g. metering, charging protocols, rate structure, and related issues.							x		
Vehicle Policies	Low Emission Vehicle AB1493 (Pavley)	2002	Establishes California standards for passenger vehicles for model years 2009–2016, and proposed standards for model years 2017–2025 expected soon.			x						
Vehicle Policies	Zero Emission Vehicle (ZEV) Program	1990	Will require a percentage of new vehicles sold in California to have zero tailpipe emissions. Requirements through 2025 are expected to be released in 2011.			x				x		

Category	Policy	Year	Description	Building Efficiency	Industry Efficiency	Transport Efficiency	Clean Electricity	Building Electrification	Industry Electrification	Transport Electrification	Biofuels	Long Term Behavior
Vehicle Policies	AB 118	2007	Provides $1.4 billion in incentives through 2015 for loans or rebates on advanced vehicles purchases, alternative fuels infrastructure, manufacturing, and research and development. In 2010 and 2011, $4.1 million has been set aside for consumer PEV rebates of up to $5,000 per vehicle.			x				x	x	
Vehicle Policies	SB 71	2009	Authorizes the California Alternative Energy and Advanced TransportationFinancing Authority to approve sales and use tax exemptions through 2020 on manufacturing equipment for PEVs and other advanced or alternative transportation or energy technologies.			x				x		
Vehicle Policies	SB 535	2010	Allows certain PEVs access to carpool lanes regardless of the number of passengers, until 2015.							x		
Vehicle Policies	SB 1455	2010	Requires the California Public Utilities Commission and the California Energy Commission to maintain a public website with links and information specific to PEVs.							x		
Other	SB 375	2008	Creates Metropolitan Planning Organizations to develop sustainable community strategies, including smart growth strategies and improved transportation planning.	x		x						x

APPENDIX 2 – DIFFERENCES BETWEEN THIS STUDY AND CALIFORNIA ENERGY FUTURE STUDY (CEF 2011).

Differences between the recent CEF study and this work (CCC) are summarized in Table A2-1 below and Figure A2-1 shows a "matched" comparison for CEF/CCC with the same total biofuel supply. Some differences are in projected demands and supply assumptions but there are also key differences in how GHG emissions are accounted for.

This study has lower fuel estimates primarily due to a lower growth rate for industry which is more consistent with historical trends in the state as energy intensive industries migrate out of state. But this may lead to more of Californians' emissions exported to production locations abroad or out of state. Thus a larger effective industry growth rate may in fact more accurately capture the full GHG impact of the state.

CEF base case biofuel supply is four times higher at 15 Bgge total compared to 3.7 Bgge for the base case here and 10 Bgge for the high biofuels case. A key difference is the assumption here that imported biofuels are limited to 25% of overall supply. Certainly it is possible that a large quantity of biofuels may be economically available and imported from abroad or from other states in the future but the CCC adopted this constraint to explore what would be required from the energy system with a more constrained biofuel supply and also to be in accordance to Executive Order S-06-06 limiting imported biofuel.

The CEF included LCA factors for all fossil fuels in its calculation of GHG emissions, whereas this report only included LCA factors for biofuels. The CEF is thus more consistent in its treatment of fuel emissions. Biofuel LCA emissions in particular are receiving much more scrutiny and policies such as the LCFS consider fuel LCA emissions. On the other hand, much of the petroleum products used in the state are refined in California and thus many oil-related emissions are already captured in state in the oil and gas industry sector. Moreover, CARB does not currently apply LCA factors to fuel combustion in its GHG inventory. Including LCA factors (while correcting for industry emissions to avoid double counting) is a more comprehensive treatment of emissions, but the research team decided to follow CARB methodology for natural gas and petroleum based fuels. This study does utilize LCA factors for biofuels as as proxy for industry-related fuel emissions from biorefineries that otherwise were not explicitly included.

	CEF 2050 Base Case	This Work (CCC) 2050 Base Case	Comments
Fuels [Bgge]			
Transport Fuel	16	14.6	CCC has lower overall fuel demand from airline freight adjustment and slightly higher truck efficiency
Non-Transport Fuel	8.9	5.9	
Industry	7.1	3.8	CCC assumes lower industry frozen efficiency growth rate in energy (0.6% vs 2.65%)
Buildings	1.8	2.1	CEF has slightly higher electrification penetration
Total fuel demand	24.9	20.5	
Base Case Biofuel Supply [Bgge]	15	3.7	
In-state biofuel	7.5	2.8	CCC biomass estimates based on 2020-2030 data; CEF at projected long term technical potential
Imported biofuels	7.5	0.9	CCC limits imported biofuels to 25% overall supply in accordance with state Executive Order S-06-06.
Calculation of fuel emissions	LCA factor for all fossil fuels	LCA for biofuels only	CEF applies LCA factor to all fossil fuels; CCC applies LCA factor to biofuels only. Currently CARB does not apply LCA factor to fossil fuel emissions.
Electricity [GWh]	513,000	424,000	CCC lower due to lower fuel demand projections and thus lower overall electricity demand for similar rates of electrification
Electricity emissions	Hinge on load balancing assumptions	Set by Carbon Cap	CEF electricity emissions hinge on load balancing emissions (e.g. natural gas turbines vs zero energy load balancing (ZELB). For this work, SWITCH does not explicitly calculate load following emissions but rather optimizes the electricity supply system subject to an overall system wide cap on emissions.
Overall GhG emissions from energy sector [MMt-CO2eq]	150	130	

Table A2-1. *Differences between this study and the CEF 2011 report.*

Finally, the CEF report highlights that emissions from load balancing in the electricity sector are a key hinge factor.   The CEF makes a best guess estimate for the amount of load balancing (e.g. gas turbines) that is needed for an electricity system high contributions of intermittent supply sources. The amount of electricity emissions then hinges on whether this can be covered with zero emission sources (some types of batteries, hydroelectric power, etc) or with fossil fuels.   This report utilizes SWITCH to model the electricity system and performs a system wide cost optimization subject to an overall carbon cap.   The model utilizes operating reserve requirements similar to the Western Wind and Solar study and finds that spinning reserve is dominated by hydroelectric power and battery storage.   The net effect is that SWITCH's overall electricity emissions are lower that the CEF base case with non-zero emission load following.
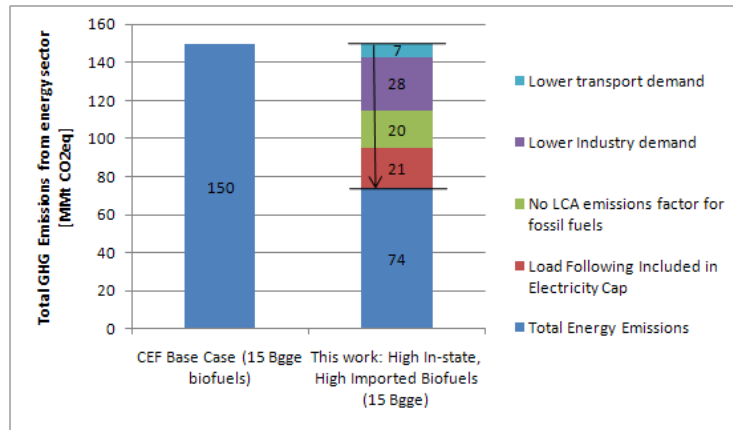
Figure A2-1. *Stack plot of overall 2050 energy emissions for CEF and this work with matched biofuel supply (15 Bgge total). This work has lower overall emissions due to lower industry and transport demand, no LCA factor applied to fossil fuels, and electricity emissions set by a carbon cap.*

APPENDIX 3: END USE MODELING DETAILS: BUILDINGS

Mid-Term Analysis Assumptions

Technical potential from retrofit and replace-on-burnout measures

For the retrofit and ROB measures, technical potential reflects the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency on a retrofit or ROB basis were taken.[20] Retrofit and ROB opportunities differ in whether the measure is typically applied or adopted before the end of the existing technology's useful life. Retrofit measures are those that are typically adopted before the end of the useful life of the existing end-use technology (e.g. replacing incandescent lamps with CFLs), whereas ROB opportunities are those that are typically adopted when the existing end-use technology needs to be replaced due to failure or performance issues.

However, retrofit and ROB measures are also similar in that these types of measures have been promoted and supported by utility programs in California for over two decades, and these measures continue to account for the vast majority of utility program offerings and utility-supported research and development. In this sense, there is a vast amount of measure-specific cost, savings, applicability, and feasibility estimates available to establish technical potential estimates, and uncertainty ranges can be developed in a bottom-up fashion that draw from the specific lessons learned from over a decade of program evaluation studies.

In this case, the research team leveraged the detailed data, analysis, and results of the 2008 Itron potential update study. The 2008 Itron update study incorporates the latest estimates of measure costs, savings, applicability, and feasibility for over 200 retrofit and ROB measures applicable to the buildings sector and commercially available in California. Note that the scope of the 2008 Itron update study was limited to assessing energy efficiency potential within the service territories of California's four IOUs – Pacific Gas & Electric, Southern California Edison, Southern California Gas, and San Diego Gas & Electric. For this study, the team extrapolated the climate-zone specific results of the 2008 Itron update study by building type and segment to the non-IOU service territories in California. In this respect, the analysis of retrofit and ROB measures in this project produces statewide estimates of technical potential based on the assessment of technical potential in California's four IOUs.

To complement the technical potential forecasts derived in the 2008 Itron potential update study, the research team also developed end-use-specific uncertainty ranges that attempt to capture key uncertainties in the estimates of technical potential from retrofit and ROB technologies and measures.

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[20] Applicability limits measure installation to situations where a qualifying end use or technology is present (e.g., water heater blankets for electric water heaters require an electric water heater to be present). Feasibility limits measure installation to situations where installation is physically practical (e.g., available space, noise considerations, and lighting level requirements are considered, among other things).

Technical potential from new construction measures

For new construction measures, technical potential reflects the amount of energy savings that would be possible if all technically applicable and feasible opportunities to improve energy efficiency in new buildings at the time of design, construction, and commissioning were taken. In contrast to retrofit and ROB opportunities, new construction efficiency strategies are typically bundles of individual measures that also leverage whole-building and systems integration to yield savings that are "larger than sum of their parts", e.g. daylighting and fenestration strategies in commercial buildings that reduce the need for interior lighting, which in turn reduces internal gains and space cooling requirements. Also in contrast with retrofit and ROB measures, new construction measures have historically represented only a small part of utility program offerings, and there is a relatively limited amount of cost, savings, and feasibility estimates available to establish technical potential estimates.

However, a number of state and national initiatives have recently placed higher priority on aggressive new construction measures, particularly initiatives promoting and setting goals for "net zero energy" (NZE) homes and buildings. These national initiatives include the U.S. DOE's Building America Program and the New Building Institute's (NBI) "Getting to Fifty" initiative (USDOE, 2009; and NBI, 2009). Building America seeks to develop design, construction, and systems engineering techniques that will support the large scale production of ZNE homes by 2020. NBI's "Getting to Fifty" initiative promotes the construction of commercial buildings that are 50% more efficient than current code-compliant buildings.

In California, the California Public Utilities Commission recently adopted two programmatic initiatives, referred to as the Big Bold Energy Efficiency Strategies (BBEES) that promote similar targets for ZNE homes and buildings in California (CPUC, 2007a). Furthermore, CPUC directed California's investor-owned utilities, as part of D.07-10-032, to include specific programs to support the implementation of three of the four BBEES initiatives in their 2009-2011 portfolio applications as well as their long-term Strategic Plans. Given this increasing focus on ZNE homes and buildings and the CPUC's recent decisions, the research team chose to develop the mid-term new construction scenario based on the timelines and savings targets for the BBEES new construction (NC) initiatives established by the CPUC in D.07-10-032. These timelines and savings targets are summarized below, along with the other key assumptions used in the residential and commercial new construction scenarios.

Zero Net Energy Residential New Construction (ZNE RNC)

To frame the mid-term new construction case for residential buildings, the research team leveraged the interim performance milestones for ZNE homes established by the CPUC for the BBEES NC initiatives, which use the Tier 2 energy efficiency requirements from the CEC's New Solar Home Partnership program (35% energy savings compared to homes meeting 2005 Title 24 performance standards) as the primary performance benchmark. The team also incorporated a set of complimentary interim milestones related to the BBEES NC initiatives based on Tier 3 efficiency requirements (55% savings compared to 2005 Title 24) that were developed in the *California Energy Efficiency Strategic Plan* (CPUC, 2008). The complete set of interim milestones used in the new construction case for residential buildings is shown in Table A3-1 below.

Note that the team treated the interim market penetration milestones defined in D.07-10-032 and the draft residential Strategic Plan as the "high" savings case, consistent with some stakeholders characterizing the BBEES milestones are "difficult but feasible" and the CPUC's own characterization of the BBEES milestones as requiring "an aggressive and creative action plan." The team then created more conservative "mid" and "low" savings cases based on trajectories of performance and market penetration milestones that were more modest and gradual over time.

For the most part, the market penetration assumptions for the natural gas analysis are identical to those developed and applied in the electric analysis. The one exception, however, is that the team adjusted the 2020 market penetration assumption for Tier 3 homes in the "high" savings case downward from the value developed for the electric analysis, from 90% to 70%. This adjustment is related to the team's assumption that rooftop solar water heating is a key measure in the "package" of advanced measures that achieve Tier 3 savings levels for gas (see more detailed discussion of the Tier 2 and Tier 3 measure "packages" below). As such, the research team wanted to ensure that our market penetration assumptions for Tier 3 homes in the "high" savings case were consistent with a recent NREL assessment that 65% of rooftops in California are suitable for solar water heating while allowing for the possibility that rooftop availability in the new construction segment will be slightly higher, on average, than NREL's assessment of rooftop availability in the current building stock.[21]

Modeling assumptions. The research team assumed that the incremental technical potential attributable to the BBEES NC initiatives is limited to the water heating and HVAC end uses in new homes in order to avoid double-counting with the lighting and appliance measures in other scenarios and to maintain consistency with the current scope of Title 24.

Table A3-1: Efficiency level and market penetration assumptions used in mid-term technical potential scenario for residential new construction

Efficiency level:	Case:	Market Penetration:			
		2011	2015	2020	2025
Tier 2	High[a]	40%	90%	100%	100%
	Mid	30%	60%	80%	100%
	Low	20%	30%	60%	90%
Tier 3	High[b]	10%	40%	90%	100%
	Mid	8%	25%	60%	95%
	Low	5%	10%	25%	40%

[a] High values reflect milestones in D.07-01-032; [b] High values reflect milestones in CPUC, 2007b.

Development of savings inputs. The key electric savings assumptions in the residential new construction scenario are based on the Tier 2 and Tier 3 performance levels – 35% and 55% energy

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[21] It should be noted that with respect to solar water heaters, the "mid" case market penetration assumptions for Tier 3 measure packages is consistent with the goals of AB 1470 (the Solar Hot Water and Efficiency Act of 2007), i.e. 200,000 cumulative installations of solar water heaters in California by 2017.

savings compared to 2005 Title 24 new homes, respectively. For the gas analysis, the unit savings assumptions are based on an analysis of "packages" of advanced gas efficiency measures that approach Tier 2 and Tier 3 performance targets, i.e. 35% and 55%, respectively. The research team conducted this supplemental analysis for potential gas savings to ground the assumed Tier 2 and Tier 3 performance targets within the technical potential of current advanced and emerging technologies and ensure that the market penetration assumptions associated with Tier 2 and Tier 3 packages were consistent with the availability of the technologies that are likely required to deliver the respective levels of gas savings.

Table A3-2 shows the packages of measures that form the basis of the team's aggregate Tier 2 and Tier 3 unit savings assumptions for the residential new construction scenario in the gas analysis. As the table shows, the Tier 2 package includes tankless water heaters, condensing furnaces, and advanced shell measures, while the Tier 3 package includes condensing water heaters coupled with solar water heaters, condensing furnaces, and advanced shell measures.[22]

Based on the performance benchmarks of these technologies and taking into account interactive effects between measures (e.g. reduction in unit savings from condensing furnaces due to implementation of advanced shell measures), the research team estimated the aggregate unit savings for Tier 2 and Tier 3 measure packages to be approximately 27% and 45%, respectively.

Table A3-2: Measure-level assumptions used to develop aggregate unit savings values in the residential new construction scenario

Measure Package:	Measure:	Performance Benchmarks:		Measure Savings:	UEC-weighted Savings*:
		Measure	Baseline Tech		
Tier 2	Tankless water heater	0.84 EF	0.60 EF	29%	27%
	Advanced shell measures	-	-	15%	
	Condensing furnace	97 AFUE	81 AFUE	12%	
Tier 3	Condensing water heater	0.86 EF	0.60 EF	30%	45%
	Solar water heater	0.5 SF	-	50%	
	Advanced shell measures	-	-	15%	
	Condensing furnace	97 AFUE	81 AFUE	12%	

* includes adjustments for interactive effects between measures

After weighting these technical unit savings using the penetration milestones in Table A3-2 and the Energy Commission's forecast of annual new construction rates, the penetration-weighted savings estimates were then applied to the baseline UECs for water heating and HVAC in new homes in each year of the forecast period.

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[22] Advanced shell measures include advanced windows, deeply insulated ducts, insulated slab edges, radiant barrier roof sheathing, R49 ceilings, insulated headers, and structural insulated panels.

Uncertainty bounds. The uncertainty bounds in our residential new construction case reflect the range of assumed market penetration rates shown in Table A3-2 above. As discussed above, we treated the BBEES market penetration milestones as the upper bound and created more modest penetration milestones to represent the middle case and the lower bound of potential savings. Note that we did not adjust the technical unit savings or annual new construction assumptions across any of the residential new construction scenarios.

Zero Net Energy Commercial New Construction (ZNE CNC)

To frame the mid-term new construction assumptions for commercial buildings, the research team leveraged the interim efficiency milestones defined by the CPUC for the BBEES NC initiatives, which use 30% energy savings compared to commercial buildings meeting 2005 Title 24 performance standards as the primary performance benchmark.

Table A3-3: Efficiency level and market penetration assumptions used in mid-term technical potential case for commercial new construction

Efficiency level:	Case:	Market penetration:			
		2011	2015	2020	2025
Tier 2	High [a]	30%	50%	70%	90%
	Mid	20%	35%	55%	75%
	Low	10%	20%	40%	60%

[a] High values reflect milestones in D.07-01-032

Note also that the research team treated the interim market penetration milestones defined in D.07-10-032 as the "high" savings case, consistent with the CPUC's own characterization of the BB CNC milestones as requiring "an aggressive and creative action plan." The team then created more conservative "mid" and "low" savings cases based on trajectories of performance and market penetration milestones that were more modest and gradual over time as shown in Table A3-3 above.

Modeling assumptions. The research team assumed that the incremental technical potential attributable to the BBEES NC initiatives is applicable to the water heating, HVAC, interior lighting, and exterior lighting end uses, in order to maintain consistency with the current scope of Title 24.

Development of savings inputs. The key savings assumption in the BB CNC scenario is based on the performance milestone defined in D.07-10-032 – 30% energy savings compared to 2005 Title 24 new buildings. For the gas analysis, the unit savings assumptions applied in the commercial new construction case are based on an analysis of "packages" of advanced gas efficiency measures that approach the 30% energy savings target. The research team conducted this supplemental analysis for commercial new construction gas savings to ground the assumed performance targets within the technical potential of current advanced technologies and ensure that the market penetration assumptions associated with these measures were consistent with the availability of the technologies that are likely required to deliver the respective levels of gas savings.

Table A3-4 shows the packages of measures that form the basis of the team's aggregate unit savings assumption for the commercial new construction case in the gas analysis. As the table shows, the new construction measure package includes condensing boilers, advanced boiler controls, and

advanced shell measures.[23] Based on the performance benchmarks of these technologies and their interactive effects (e.g. reduction in unit savings from condensing boilers due to implementation of advanced shell measures), the research team estimated the aggregate unit savings for commercial new construction measure packages to be approximately 28%.

Table A3-4: Measure-level assumptions used to develop aggregate unit savings values in the commercial new construction case

Measure Package:	Measure:	Performance Benchmarks:		Measure Savings:	EUI-weighted Savings*:
		Measure	BaselineTech		
Tier 2	Condensing boiler	95 AFUE	80 AFUE	12%	
	Advanced shell measures	-	-	35%	29%

* includes adjustments for interactive effects between measures

After weighting technical unit savings using the penetration milestones in Table A3-3 and the CEC's forecast of annual new construction rates, the penetration-weighted savings estimates were then applied to the baseline EUIs for water heating, HVAC, interior lighting, and exterior lighting in new commercial buildings in each year of the forecast period.

Uncertainty bounds. The uncertainty bounds in the research team's commercial new construction case reflect the range of assumed market penetration rates shown in Table A3-3 above. As discussed above, the research team treated the BBEES market penetration milestones as the upper bound and created more modest penetration milestones to represent the middle case and the lower bound of potential savings. Note that the team did not adjust the technical unit savings or annual new construction assumptions across any of the commercial new construction cases.

Long-Term Analysis Assumptions

Commercial Buildings

Lighting

The energy intensity of commercial lighting was decomposed into the following three factors:

*EUI lighting (kWh/ft2) = Watts/lumen * lumens/ft2 * full load hours*

In this decomposition, the first term (watts per lumen) accounts for the luminous efficacy of the light source. The second term (lumens/ft2) describes the artificial lighting requirements. The third term (hours) describes the temporal use of the artificial lighting system. Table A3-5 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for commercial lighting.

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[23] Advanced shell measures include high-performance insulation, dynamic windows, and passive solar design. The assumed unit savings associated with these measures is consistent with NREL's assessment of the technical potential of zero-energy building strategies in the commercial sector.

Table A3-5. Summary of benchmark measures considered in estimating the technical potential of energy savings from commercial lighting.

	Luminous Efficacy	Lighting Requirements	Temporal Use
Benchmark measures considered for 2050	Technological improvements in light source (e.g. LEDs, higher efficiency fluorescents)	Task lighting Daylight harvesting User controls	Daylighting controls Advanced occupancy sensors Behavioral change

The major improvement in the luminous efficacy (measured in lumens per watt) of light sources from 2025 to 2050 is expected to be a result of increasing market penetration of solid state lighting technologies (i.e. LEDs) and the increasing efficacy of both LEDs and fluorescent light sources. Ongoing RD&D projects of LED technology suggest substantial gains in efficacy (as high as 1.5 times that in 2025) and LED market penetration ranging from 50% to 100% according to experts (Gauna, 2009; and Steele, 2009).

Lighting requirements (measured in lumens per sq. ft. or foot-candles) refers to the lighting level appropriate for specific purposes (e.g. display, reading, etc.). Over the years, required lighting levels have decreased substantially as better designs have been developed that account for task requirement, color of light (i.e. cool, warm, hue, etc.), reflectance of various surfaces (e.g. walls, ceilings, flooring, etc.), layout of space, daylighting, and control systems (e.g. that allow occupants to modify the level of lighting and also provide instant feedback on energy saved). Availability of sophisticated simulation tools and increasing awareness among all stakeholders (i.e. owners, architects, designers, occupants, etc.) is expected to lead to further decrease in lighting intensity in various types of facilities (Vaidya, 2009).

The operational pattern of lighting use has the potential for substantial savings according to experts (Horton, 2009). Strategies such as daylighting (i.e. using daylight where possible instead of artificial light), controls (i.e. switches that allow occupants to switch off lights when not needed), sensors that switch off lights when no occupant is detected in the target spaces, and finally behavioral change under which motivate the occupants to reduce lighting usage have been demonstrated in the U.S. and other parts of the world.

In Table A3-6, the high/mid/low savings estimates developed for commercial lighting are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Table A3-6. Case-specific assumptions for each component of commercial lighting intensity considered in 2050 forecast.

Lighting Savings	Luminous efficacy	Lighting level	Temporal Use
High	High (~100%) LED mkt. penetration High LED efficacy (>200 lm/W)	High use of task-lighting High levels of both capability and awareness for occupants in adjusting lighting level according to needs High use of daylighting and other design strategies such as surfaces, paints, textures, layouts, etc.	Most switches with digital dimming capability Most spaces have "Smart" occupancy sensors
Mid	High LED mkt. penetration Medium LED efficacy (~200 lm/W)	High use task-lighting Medium levels of both capability and awareness for occupants in adjusting lighting level according to needs Low use of daylighting and other design strategies such as surfaces, paints, textures, layouts, etc.	~75% switches with digital dimming capability ~75% spaces have "Smart" occupancy sensors
Low	Medium LED mkt. penetration Medium LED efficacy (< 200 lm/W)	Medium use task-lighting Low levels of both capability and awareness for occupants in adjusting lighting level according to needs Low use of daylighting and other design strategies such as surfaces, paints, textures, layouts, etc.	~50% switches with digital dimming capability ~50% spaces have "Smart" occupancy sensors

Space Cooling

The energy intensity of commercial space cooling was decomposed into the following three factors:

*EUI space cooling (kWh/ft2) = kW/ton * tons/ft2 * full load hours*

In this decomposition, the first term (kW/ton) accounts for the efficiency of the cooling equipment (e.g. chiller). The second term (tons/ft2) describes the cooling requirements of the building. The third term (full load hours) describes the operational pattern of the cooling system. In the case of space cooling, many measures that serve to reduce full load hours also serve to reduce total cooling load of a building. For example, most advanced building envelope measures serve to reduce both the full load hours of cooling required to maintain indoor temperatures as well as the peak cooling load. In order to avoid double-counting potential savings from measures that significantly impact both cooling requirements and full load hours, the study team collapsed those two terms for purposes of developing long-term savings estimates for commercial space cooling. Instead, the study team developed savings estimates for three distinct types of efficiency strategies that impact

the collapsed cooling requirement/full load hour term – controls, reductions in internal loads, and building envelope measures. Table A3-7 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for commercial space cooling.

Table A3-7: Summary of benchmark measures considered in estimating the technical potential of energy savings from commercial space cooling.

	Cooling Equipment Efficiency	Cooling Requirement and Operational Pattern		
		Controls	Internal Loads	Building Envelope
Benchmark measures considered for 2050	Technological improvements in cooling equipment	Adaptive/ "fuzzy" controls Faster fault detection Automated optimization	Adaptive occupant comfort Optimal equipment sizing	Building orientation Fenestration Operable windows Glass-to-opaque ratio

Commercial space cooling systems are characterized in terms of two main technologies: central chillers and packaged units. Typically, central chillers – especially, water-cooled centrifugal chillers - are more efficient than packaged units. However, ADL (2001) note that, in recent years, there is a growing trend towards using more packaged units in place of central chillers. Various sources such as the Consortium for Energy Efficiency (CEE), American Council for Energy Efficient Economy (ACEEE), and the experts interviewed by the research team indicated that relatively small improvements in efficiency of central chillers and packaged units are expected since the existing efficiency is already close to the thermodynamic limits (Hydeman, 2009).

Experts note that the largest potential for energy savings could be from reducing cooling requirements by using strategies such as controls/sensors (e.g. thermostats, EMS, etc.), envelope (e.g. building orientation, glass-to-opaque surface ratio, operable windows, etc.), and internal loads (e.g. occupant comfort) – (Hydeman, 2009).

ADL (2001) cite one example of advanced controls referred to as "adaptive/fuzzy" controls that "learn" and "optimize" the cooling equipment operation constantly. Advanced sensors can also lead to faster fault detection and reduce periods when system is operating sub-optimally. Breuker and Braun (1999) estimate energy savings of 5–20% due to implementation of onboard diagnostics for non-economizer related faults.

A relatively new research area in space cooling technology is the concept of "adaptive" occupant comfort standards. University of California at Berkeley's Center for Built Environment (CBE) has conducted several studies that attempt to systematically assess the occupant comfort levels in response to a varying set of internal environmental conditions. Zhang et al. (2008) estimate that simulated annual energy savings with the Task Ambient Conditioning (TAC) system in Fresno, Oakland, and Minneapolis were each about 40% with intensive use of TAC (allowing 18-30ºC ambient interior temperature), and 30% with a moderate use (in 20-28ºC ambient temperature).

Better design of building envelope features such as glass-to-opaque ratio, fenestration, building orientation, operable windows, and others are also cited by experts as a source of substantial

energy savings. Mowris (2006) summarized studies by Lawrence Berkeley National Laboratory, Florida Solar Energy Center (FESC), and DEER where the average energy savings from strategies targeted to envelopes ranged from 10 to 30%.

Table A3-8: Case-specific assumptions for each component of commercial space cooling intensity considered in 2050 forecast.

Cooling Savings	Cooling Equipment Efficiency	Controls	Internal Loads	Building Envelope
High	~20% improvement in efficiency High level of switching from central to packaged units	High penetration of advanced controls/sensors	High use of adaptive comfort systems	Low glass-to-opaque ratio High use of fenestration Some use of operable windows
Mid	~10% improvement in efficiency Mid level of switching from central to packaged units	Medium penetration of advanced controls/sensors	Medium use of adaptive comfort systems	Medium glass-to-opaque ratio High use of fenestration No use of operable windows
Low	No or minimal improvement in efficiency; Low level of switching from central to packaged units	Low penetration of advanced controls/sensors	Low use of adaptive comfort systems	High glass-to-opaque ratio Low use of fenestration No use of operable windows

In Table A3-8, the high/mid/low savings estimates developed for commercial space cooling are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Space Heating

The energy intensity of commercial space heating was decomposed into the following three factors:

*EUI space heating (kWh/ft2) = kW/kbtuh * kbtuh/ft2 * full load hours*

In this decomposition, the first term (kW/kbtuh) accounts for the technical efficiency of the space heating equipment. The second term (kbtuh/ft2) describes the space heating requirements of commercial buildings. The third term (full load hours) describes the operational pattern of the space heating system. As was the case with commercial space cooling, many measures that serve to reduce full load hours of commercial space heating also serve to reduce the total heating load of a building. In order to avoid double-counting potential savings from measures that significantly impact both total heating loads and full load hours, the study team collapsed those two terms for purposes of developing long-term savings estimates for commercial space heating. Instead, the

study team developed savings estimates for three distinct types of efficiency strategies that impact the collapsed heating load/full load hour term – controls, reductions in internal loads, and building envelope measures. Table 18-9 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for commercial space heating.

Table A3-9: Summary of benchmark measures considered in estimating the technical potential of energy savings from commercial space heating

	Heating Equipment Efficiency	Heating Requirement and Operational Pattern		
		Controls	Internal Loads	Building Envelope
Benchmark measures considered for 2050	Technological improvements in heating equipment	Adaptive/ "fuzzy" controls Faster fault detection Automated optimization	Adaptive occupant comfort Optimal equipment sizing	Building orientation Fenestration Operable windows Glass-to-opaque ratio

Space heating energy use is characterized in terms of two types of core systems: boilers (for large loads) and furnaces (for small loads). In this study, energy savings from only natural-gas-fired space heating systems such as boilers and furnaces are modeled. Substantial energy savings in 2050 from electric systems as compared with 2025 are not likely and technologies such as ground-source heat pumps appear to have small potential in California, especially, for commercial facilities (Hydeman, 2009).

Various sources such as the CEE, ACEEE, and the experts interviewed by the research team indicated that very small improvements in efficiency of boilers and furnaces are expected since the existing efficiency is already close to the thermodynamic limits (Hydeman, 2009).

Space cooling and heating systems are typically designed together as part of a single HVAC system in most commercial applications. Therefore strategies used for energy savings from reducing cooling requirements are similar to those for reducing heating requirements. For example, advanced controls and sensor mechanisms that can be used for optimizing the cooling system can also be used for optimizing the heating system operation. However, some of the design strategies for reducing cooling requirements have an exactly opposite effect on the heating requirement. For example, a lower glass-to-opaque ratio will reduce heat gain thereby reducing cooling requirement. However, reducing heat gain will also result in more heating requirement. Consequently, the design of both cooling and heating systems must be done in a combined manner in order to minimize the total annual energy used by the facility. In this analysis, we assume that the cooling load dominates the HVAC design considerations and hence the measures that are likely to reduce cooling requirements are given priority over those that reduce heating requirements.

In Table A3-10, the high/mid/low savings estimates developed for commercial space heating are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Table A3-10: Case-specific assumptions for each component of commercial space heating intensity considered in 2050 forecast.

Space Heating Savings	Heating Equipment Efficiency	Controls	Internal Loads	Building Envelope
High	~3% improvement in efficiency	High penetration of advanced controls/sensors	High use of adaptive comfort systems	Low glass-to-opaque ratio High use of fenestration Some use of operable windows
Mid	~2% improvement in efficiency	Medium penetration of advanced controls/sensors	Medium use of adaptive comfort systems	Medium glass-to-opaque ratio High use of fenestration No use of operable windows
Low	No or minimal improvement in efficiency	Low penetration of advanced controls/sensors	Low use of adaptive comfort systems	High glass-to-opaque ratio Low use of fenestration No use of operable windows

Ventilation

The energy intensity of commercial ventilation was decomposed into the following three factors:

$$EUI\ ventilation\ (kWh/ft2) = kW/ACH * ACH/ft2 * full\ load\ hours$$

In this decomposition, the first term (kW/ACH) accounts for the technical efficiency of the air handler equipment. The second term (ACH/ft2) describes the ventilation requirements of commercial buildings, represented as the number of air changes per hour (ACH) required per square foot of floor area. The third term (full load hours) describes the operational pattern of the ventilation system. Ventilation systems distribute heating and cooling energy to various parts of the facility. However, the most important function of the ventilation system is ensuring the indoor air quality meets the standards (e.g. removal of carbon dioxide and toxins). As was the case with commercial space cooling and space heating, many measures that serve to reduce full load hours of commercial ventilation systems also serve to reduce the total ventilation requirements of a building. In order to avoid double-counting potential savings from measures that significantly impact both total ventilation requirements and full load hours, the study team collapsed those two terms for purposes of developing long-term savings estimates for commercial ventilation. Table A3-11 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for commercial ventilation.

Table A3-11: Summary of benchmark measures considered in estimating the technical potential of energy savings from commercial ventilation systems

	Ventilation Equipment Efficiency	Ventilation requirement and Operational Hours
Benchmark measures considered for 2050	Technological improvements in ventilation equipment	CO_2 sensors Demand control ventilation Advanced diagnostics and fault detection

Most of the key measures that have the highest technical potential of energy savings such as replacing constant speed drives with variable speed drives, moving from constant air volume systems to variable air volume systems, and switching from standard motors to premium motors are already included in the mid-term (2025) forecast (Itron and KEMA, 2008). Experts interviewed by the research team noted that significant further savings from variable speed drives and premium efficiency motors are not likely (Hydeman, 2009; and Ramirez, 2009).

The potential for further energy savings from the ventilation system are likely to result from more penetration of advanced environmental quality sensors, demand control ventilation, and diagnostic systems. ACEEE (2004) notes that using levels of CO2 and toxins to activate ventilation in areas where occupancy levels fluctuate substantially can result in energy savings from ventilation systems that are as high as 20% compared to the standard method for operating ventilation systems where maximum occupancy levels at all times are assumed.

In Table A3-12, the high/mid/low savings estimates developed for commercial ventilation are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Table A3-12: Case-specific assumptions for each component of commercial ventilation intensity considered in 2050 forecast.

Ventilation Savings	Controls and Internal Loads
High	~75% penetration of advanced sensors and DCV
Mid	~25% penetration of advanced sensors and DCV
Low	~0% penetration of advanced sensors and DCV

Water Heating

The energy intensity of commercial water heating was decomposed into the following three factors:

*EUI water heating (kWh/ft2) = kW/kbtuh * kbtuh/ft2 * full load hours*

In this decomposition, the first term (kW/kbtuh) accounts for the technical efficiency of the water heating equipment. The second term (kbtuh/ft2) describes the water heating requirements of

commercial buildings. The third term (full load hours) describes the operational pattern of the water heating system. As was the case with commercial space cooling and heating, many measures that serve to reduce full load hours of commercial water heating also serve to reduce the total water heating load of a building. In order to avoid double-counting potential savings from measures that significantly impact both total water heating loads and full load hours, the study team collapsed those two terms for purposes of developing long-term savings estimates for commercial water heating. Instead, the study team considered savings from two distinct types of efficiency strategies that impact the collapsed heating load/full load hour term – controls and distribution system efficiency. Table A3-13 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for commercial water heating.

Table A3-13: Summary of benchmark measures considered in estimating the technical potential of energy savings from commercial water heating systems

	Water Heating Equipment Efficiency	Heating Requirement and Operational Pattern	
		Controls	Distribution Efficiency
Benchmark measures considered for 2050	Technological improvements in boilers, storage water heaters, and storage water heaters coupled with solar water heaters	Demand-controlled circulating pumps Circulation timers	Pipe insulation Distribution system design

Long-term (2050) technical potential of energy savings from commercial water heating systems as compared with 2025 forecast was modeled for three types of systems – boilers (for large water heating requirements), storage water heaters (for relatively small water heating requirements), and storage systems coupled with solar water heaters. Within boilers systems, various sources such as CEE, ACEEE, and water heating technology experts indicated that only very small improvements in efficiency of boilers are expected beyond the performance of the condensing boiler designs already considered in the 2025 forecast, since the efficiency of condensing boilers is already close to the thermodynamic limits (Parker, 2009; and Ramirez, 2009). Similarly for storage water heater systems, expert opinion suggests that only small efficiency improvements are expected beyond those captured by the high-efficiency storage systems already considered in the 2025 analysis. In the case of solar water heaters, the 2025 analysis already captures all of the feasible market for solar water heaters coupled with storage systems. It is possible that additional incremental savings from commercial solar water heater systems could be realized from increases in the average solar fraction of future systems, but there is currently no evidence in the R&D literature to support such an estimate.

In Table A3-14, the high/mid/low savings estimates developed for commercial water heating are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Table A3-14: Case-specific assumptions for each component of commercial water heating intensity considered in 2050 forecast.

Water Heating Savings	Water Heating Equipment Efficiency
High	~3% improvement in efficiency for boilers ~7% improvement in efficiency for storage WH
Mid	~2% improvement in efficiency for boilers ~5% improvement in efficiency for storage WH
Low	~1% improvement in efficiency for boilers ~2% improvement in efficiency for storage WH

Other Commercial End Uses

While lighting, space cooling, space heating, ventilation, and water heating are the dominant end uses in commercial buildings, commercial cooking, refrigeration, office equipment, and miscellaneous end-uses each account for significant shares of current commercial energy consumption. For these end uses, the study team developed substantial energy savings estimates for the 2025 forecast based primarily on the results of Itron's 2008 potential update study. Based on interviews with technology experts and a review of the technology literature, the study team determined that effectively all of the known technical potential for these end uses is accounted for in the 2025 forecast and that very little, if any, additional potential will be available from these commercial end uses without a significant shift in the respective current technology paradigms. For example, the highest efficiency commercial refrigeration system identified in the USDOE's recent TSD for the commercial refrigeration equipment rulemaking delivers relative savings roughly equivalent to the aggregate savings from the individual measures analyzed in Itron's 2008 potential update study. In this respect, estimating additional incremental savings for the 2025-2050 period would require predicting a shift away from compressor-based mechanical refrigeration systems, for which there is no evidence in the current R&D literature.

As such, the study team did not develop incremental savings potential estimates for commercial cooking, refrigeration, office equipment, and miscellaneous end uses beyond the technical potential savings reflected in the 2025 forecast.

Residential Buildings

Residential Space Heating

The energy intensity of residential space heating was decomposed into the following three factors:

$$UEC\ space\ heating\ (kWh/home) = kW/kbtuh * kbtuh/home * full\ load\ hours$$

In this decomposition, the first term (kW/kbtuh) accounts for the technical efficiency of the space heating equipment. The second term (kbtuh/home) describes the space heating requirements of residential buildings. The third term (full load hours) describes the operational pattern of the space heating system. As was the case with commercial space heating, many measures that serve to reduce full load hours of residential space heating also serve to reduce the total heating load of a building. In order to avoid double-counting potential savings from measures that significantly impact both total heating loads and full load hours, the study team collapsed those two terms for purposes of developing long-term savings estimates for residential space heating. Instead, the study

team focused on developed savings estimates for advanced building envelope measures that impact the collapsed heating load/full load hour term. Table A3-15 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for residential space heating.

Table A3-15: Summary of benchmark measures considered in estimating the technical potential of energy savings from residential space heating.

	Heating Equipment Efficiency	Building Envelope
Benchmark measures considered for 2050	Technological improvements in heating equipment	Building orientation Fenestration Advanced insulation

Space heating energy use in residential homes is characterized in terms of one principal type of heating system: forced-air furnaces. The primary high-efficiency benchmark technology for furnace systems is condensing furnaces. This particular technology is currently available in California and is included in the 2025 forecast. Evidence from the literature suggests that small marginal performance improvements are possible over current condensing furnaces, but these efficiency improvements would be minimal given that current condensing furnaces already perform close to thermodynamic limits.

In the absence of a paradigm shift away from condensing furnace technologies, the most significant opportunities for space heating energy savings over the long-term will come from advanced building envelope measures. While the 2025 forecast includes several key insulation measures currently available (R-13 wall insulation and R-30 ceiling insulation), significant additional space heating savings are possible through the comprehensive use of advanced windows, deeply insulated ducts, insulated slab, radiant barrier roof sheathing, R-49 ceilings, insulated headers, and structurally-insulated panels. Additionally, passive solar architecture in new homes also offers the opportunity for significant incremental space heating savings over the long-term (Parker, 2009).

In Table A3-16, the high/mid/low savings estimates developed for residential space heating are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Table A3-16: Case-specific assumptions for each component of residential space heating intensity considered in 2050 forecast.

Space Heating Savings	Heating Equipment Efficiency	Building Envelope
High	No or minimal improvement in efficiency	High penetration of advanced fenestration and insulation technologies High penetration of passive solar architecture in new homes
Mid	No or minimal improvement in efficiency	Moderate penetration of advanced fenestration and insulation technologies Moderate penetration of passive solar architecture in new homes
Low	No or minimal improvement in efficiency	Low penetration of advanced fenestration and insulation technologies Low penetration of passive solar architecture in new homes

Residential Water Heating

The energy intensity of residential water heating was decomposed into the following three factors:

*UEC water heating (kWh/home) = kW/kbtuh * kbtuh/home * full load hours*

In this decomposition, the first term (kW/kbtuh) accounts for the technical efficiency of the water heating equipment. The second term (kbtuh/home) describes the water heating requirements of residential buildings. The third term (full load hours) describes the operational pattern of the water heating system. As was the case with residential space heating, many measures that serve to reduce full load hours of residential water heating also serve to reduce the total water heating load of a home. In order to avoid double-counting potential savings from measures that significantly impact both total water heating loads and full load hours, the study team collapsed those two terms for purposes of developing long-term savings estimates for residential water heating. Instead, the study team considered savings from two types of efficiency strategies that impact the collapsed heating load/full load hour term – demand reduction and reducing losses. Table A3-17 summarizes the benchmark measures that were used to develop the long-term technical potential savings estimates for commercial water heating.

Table A3-17: Summary of benchmark measures considered in estimating the technical potential of energy savings from residential water heating systems.

	Water Heating Equipment Efficiency	Heating Requirement and Operational Pattern	
		Demand Reduction	Loss Reduction
Benchmark measures considered for 2050	Technological improvements in storage water heaters and solar water heaters	Faucet aerators Low-flow shower heads Water-efficient appliances	Pipe insulation Distribution system design

Long-term (2050) technical potential of energy savings from residential water heating systems as compared with 2025 forecast was modeled for two types of systems – storage water heaters and solar water heaters. Within storage systems, water heating technology experts indicated that modest improvements in efficiency of storage water heaters are expected beyond the performance of the condensing water heater designs already considered in the 2025 forecast, but the magnitude of those improvements will be moderated by thermodynamic limits (Parker, 2009). In the case of solar water heaters, the 2025 analysis already approximately half of the feasible roof space for solar water heater applications in California's residential sector. NREL estimates that the maximum feasible share of residential roof space in California is 65% (Denholm, 1997). It is thus possible that additional incremental savings from residential water heaters could be realized by addressing the entire feasible market. Additionally, incremental savings are also possible from increases in the average solar fraction of future solar water heater systems from the value assumed in the 2025 forecast (50%).

In Table A3-18, the high/mid/low savings estimates developed for residential water heating are summarized with respect to the assumptions about each of the end-use intensity components and the respective benchmark technologies described above.

Table A3-18: Case-specific assumptions for each component of residential water heating intensity considered in 2050 forecast.

Water Heating Savings	Water Heating Equipment Efficiency
High	~29% improvement in efficiency for storage WH ~50% improvement in efficiency for solar WH
Mid	~23% improvement in efficiency for storage WH ~40% improvement in efficiency for solar WH
Low	~21% improvement in efficiency for storage WH ~20% improvement in efficiency for solar WH

Residential Electric End Uses

For residential electric end uses, the study team leveraged the long-term energy savings estimates developed in a previous PIER study that focused on the long-term electric efficiency potential in California's residential sector (Rufo and North, 2007). Indeed, the scope of this study was designed to directly complement and build upon the previous PIER study, i.e. to develop long-term savings estimates for residential gas end uses, commercial electric end uses, and commercial gas end uses

such that the combined results provide a comprehensive assessment of long-term technical potential for electricity and natural gas savings in California's residential and commercial buildings sector. As such, this study largely carried over the long-term end-use savings estimates developed in Rufo and North (2007). However, the study team made some adjustments to the previously-developed savings estimates in order to maintain internal consistency with the savings estimates developed for commercial electric end uses and residential and commercial gas end uses. Additionally, some adjustments were necessary to avoid double-counting between the 2025 technical potential estimates (as estimated in Itron's 2008 potential update study) and the 2050 technical potential estimates. The key adjustments to the previous long-term end-use savings estimates developed in Rufo and North (2007) are summarized below.

For space cooling, space heating, and furnace fans in new construction, the study team adjusted the previous 2050 savings estimates downward to be consistent with the ZNE new homes assumptions. For space cooling and space heating in existing homes, the study team adjusted the previous 2050 savings estimates downward to be consistent with the savings assumptions developed for advanced shell measures in the long-term residential gas analysis.

For lighting, the study team revised the savings estimates for both 2025 and 2050 to reflect the LED feasibility and efficacy assumptions developed for the commercial lighting analysis. This revision resulted in an upward adjustment in the residential lighting potential compared to the previous savings estimates developed in Rufo and North (2007).

For pool pumps, the study team revised the savings estimates for both 2025 and 2050 to reflect the feasibility and market availability of variable-speed pool pumps and PV-powered pool pumps. Neither of these emerging technologies was considered in Rufo and North (2007), and this revision resulted in a significant upward adjustment in residential pool pump potential compared to the previous estimates developed in Rufo and North (2007).

Finally, for clothes washers and residential plug loads, the study team shifted the potential estimates developed in Rufo and North (2007) from the 2050 period to the 2025 period. This revision was based on the near-term availability of the two benchmark technologies that formed the basis of the savings estimates in the previous study, i.e. high-speed, horizontal axis clothes washers and reductions in standby power draws from residential plug loads. In the former case, these units are already commercially available. In the latter case, the USEPA's Energy Star program already targets standby power levels in home electronics and office equipment, and these specifications are likely to be integrated into federal appliance standards over the near term.

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APPENDIX 4 – LONG TERM BEHAVIOR MODEL ASSUMPTIONS.

Transportation

Drive less (carpool, walking, biking, reduce distances…)

For each five-year period, GHG savings for driving less are calculated as:

GHG = HH * VMT * AR * CI / 1000

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

VMT = 23,753 miles per household increasing to 28,796

AR = Adoption rate, scaled linearly over 40 years from:

    Nominal Adoption: 0% to 16% adoption rate of 30% lower VMT per household

    High Adoption: 0% to 67% adoption rate of 30% lower VMT per household

CI = GHG intensity:

    Nominal and High Adoption: Passenger vehicles starting at 0.39 kgCO2e/mile to 80-90%
reduction in 2050 (RPS/LCFS regime) to 40% reduction (fossil fuel replacement with improved
vehicle gas mileage).

Telecommute to work

For each year from 2010 to 2050, GHG savings for driving less are calculated as:

GHG = HH * (AR-ARb) * RT * Dm * 12 * CI * (1-TE) / 1000

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

ARb = adoption rate in year 2010 = 4%

AR = Adoption rate, scaled linearly over 40 years from:

    Nominal Adoption: 4% to 20%

    High Adoption: 4% to 67%

RT = roundtrip miles to work = 30

Dm = Days per month taking action = 4

CI = GHG intensity:

    Nominal and High Adoption: Passenger vehicles starting at 0.39 kgCO2e/mile to 80-90%
reduction in 2050 (RPS/LCFS regime) to 40% reduction 40% reduction (fossil fuel replacement
with improved vehicle gas mileage).

TE = tradeoff effect from using more energy at home = 0.25, i.e. savings are reduced by 25%

Take public transit

GHG = HH * Mi * AR * CI – HH * Mi * AR * CIpt / 1000

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

Mi = average miles household takes public transit in baseline year = 870

AR = Adoption rate, scaled linearly over 40 years from:

      Nominal Adoption: 12% to 22% increase: 80% increase in usage

      High Adoption: 12% to 35%: 190% increase in usage

CI = GHG intensity:

      Nominal and High Adoption: Passenger vehicles starting at 0.39 kgCO2e/mile to 80-90% reduction in 2050 (RPS/LCFS regime) to 40% reduction 40% reduction (fossil fuel replacement with improved vehicle gas mileage).

CIpt= GHG intensity of public transit, scaled linearly over 40 years from:

      Nominal Adoption: 0.179 kgCO2e/mile to 0.16 kgCO2e/mile

      High Adoption: 0.179 kgCO2e/mile to 0.16 kgCO2e/mile

Healthier Diets

GHG = HH * AR * (FF + NFF)

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

AR = Adoption rate, scaled linearly over 40 years from:

      Nominal Adoption: 0% to 28%

      High Adoption: 0% to 67%

FF= GHG savings per household from fossil fuels, scaled linearly over 40 years from:

      Nominal and High Adoption: 1.05 to 0.32 tCO2e/household

NFF= GHG savings per household of CH4 and N2O, scaled linearly over 40 years from:

      Nominal and High Adoption: 0.45 to 0.27 tCO2e/household

Methane is released through manure and anaerobic digestion of ruminant animals, particularly cows. Methods for reducing methane emissions include changing animal feed and manure management. Nitrous oxide (N_2O) is released when nitrogen-based fertilizers are oxidized in fields. Fertilizer management and no- and low-tillage agricultural practices can greatly reduce these emissions with positive net financial benefits to farmers.

Waste Less Food

Americans waste about 30% of food they purchase (1000 of 3700 calories per day total). Total household emissions from food are 7.5 tCO2e (Jones & Kammen, 2011) with 2.25 tCO2e wasted. We assume food waste is reduced by 25% (0.56 tCO2e) for 13% (low) and 26% (high) of households. Seventy percent of emissions (0.39 tCO2e) are from fossil fuels and 30% (0.17 tCO2e) are from methane and nitrous oxide .

GHG = HH * AR * (FF + NFF)

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

AR = Adoption rate, scaled linearly over 40 years from:

      Nominal Adoption: 0% to 12%

      High Adoption: 0% to 67%

FF= GHG savings per household from fossil fuels, scaled linearly over 40 years from:

      Nominal and High Adoption: 0.39 to 0.12 tCO2e/household

NFF= GHG savings per household of CH4 and N2O, scaled linearly over 40 years from:

      Nominal and High Adoption: 0.0.17 to 0.10 tCO2e/household

Reduce Waste

Reducing total materials sent to municipal solid waste reduces emissions from the processing of raw materials and industrial processes. A number of behavioral actions are possible, including purchasing products with reduced packaging, shifting from paper to information technology and extending the life of products consumed. These actions provide the same value to consumers, with fewer life cycle emissions.

Californians generate 26 million metric tons of waste and recycling per year, or 1.86 metric tons of total materials per household (CalRecycle). We assume materials reduction of 7% (low) and 22% (high). According to EPA's WARM Model, each metric ton of materials reduced prevents 3.7 metric

tons of CO2e from being released to the atmosphere. Using data provided by CalRecycle on the composition of California's waste stream, combined with data from the EPA WARM Model, we estimate that this 3.7 tCO2e per ton of materials reduction is distributed as: 1.5 mtCO2e from production, 0.1 mtCO2e from transportation and 2.1 mtCO2e from land use.

GHG = HH * AR * 1.86 * (EFp + EFt + EFlu)

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

1.86 = total GHG emissions reduction opportunity per household in mtCO2e/yr

AR = Adoption rate, scaled linearly over 40 years from:

      Nominal Adoption: 0% to 22% of households reducing waste by 33%

      High Adoption: 0% to 67% reducing waste by 33%

EFp = mtCO2e per ton of material reduced from production, scaled linearly over 40 years:

      Nominal and High Adoption: from 1.5 to 0.4 mtCO2e/ton (70% reduction)

EFt = mtCO2e per ton of material reduced from transport, scaled linearly over 40 years:

      Nominal and High Adoption: from 0.1 to 0.05 mtCO2e/ton (50% reduction)

EFlu = mtCO2e per ton of material reduced from land use, scaled linearly over 40 years:

      Nominal and Adoption: from 2.1 to 1.3 tCO2e/ton (40% reduction)

Note: material generation per capita in U.S. has increased from 47% since 1970.

Increase Recycling

Californians currently recycle about 54% (14 million metric tons per year) of total materials (CalRecycle). Each metric ton of mixed materials recycled reduces net GHG emissions by 4.1 mtCO2e, based on the materials composition of California's recycling stream (CalRecycle) and emission factors provided by the California Air Resources Board. Through a combination of behavior change and enabling policies and programs we assume recycling rates increase to 75% (low) and 90% (high) of total materials.

GHG = HH * (AR – ARb) * 1.86 * (EFp + EFt + EFlu)

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

1.86 = total GHG emissions reduction opportunity per household in mtCO2e/yr

AR = Adoption rate, scaled linearly over 40 years from:

>> Nominal Adoption: 54% to 80%

>> High Adoption: 54% to 90%

ARb = adoption rate for baseline year = 54%

EFp = mtCO2e per ton of material recycled from production, scaled linearly over 40 years:

>> Nominal and High Adoption: from 1.6 to 0.5 mtCO2e/ton (70% reduction)

EFt = mtCO2e per ton of material recycled from transport, scaled linearly over 40 years:

>> Nominal and High Adoption: from 0.1 to 0.05 mtCO2e/ton (50% reduction)

EFlu = mtCO2e per ton of material recycled from land use, scaled linearly over 40 years:

>> Nominal and High Adoption: from 2.3 to 1.3 tCO2e/ton (40% reduction)

Here, the "adoption rate" is effectively the overall rate of recycling.

Note that for the behavior treatment, we only include energy emissions (no CH4 or N_2O reductions).

Reduce Air Travel

Californians fly about 7,800 miles per household per year. Each mile flown produces 223 grams of CO2e from combustion emissions and changes in high altitude atmospheric chemistry. We assume reductions of 10% (low) and 20% (high) by increasing teleconferencing for business trips and some personal trips.

GHG = HH * Mi * AR * CI / 1000000

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

Mi = average miles flown per household in baseline year = 7,800 miles

AR = Adoption rate, scaled linearly over 40 years from:

>> Nominal Adoption: 0% to 30% of population fly 30% less than baseline

>> High Adoption: 0% to 67% of population fly 30% less than baseline

CI = GHG intensity, scaled linearly over 40 years from:

>> Nominal and High Adoption: 223 to 178 grams CO2e per passenger mile

Note: CARB GHG currently counts intrastate airline travel and intrastate freight miles only which represent a small fraction of overall air miles (<7% of total miles).

Home Energy Conservation

Each California household produces about 2 mtCO2 from electricity and 2 mtCO2e from natural gas each year. A large number of energy efficiency and conservation measures are possible to reduce these emissions. Energy efficiency improvements are included elsewhere in this report. Here we only consider conservation measures, such as adjusting thermostat settings, turning off lights and appliances when not in use, drying clothes on the line and hot water conservation measures. Various studies estimate cost-effective savings of 20% or more using a combination of energy efficiency and conservation measures (Dietz et al., Laitner and Erhardt-Martinez). A high end potential for conservation measures alone would be about 10%, or 0.4 mtCO2e, which we adjust up to 0.5 mtCO2e to account for indirect emissions.

GHG = HH * (AR – ARb) * CS

Where

GHG = Savings of greenhouse gases in CO_2 equivalents

HH = number of California households in given year

AR = Adoption rate, scaled linearly over 40 years from:

      Nominal Adoption: 20% to 40%

      High Adoption: 20% to 67%

ARb = 20%

CS = potential GHG savings from conservation measures, scaled linearly over 40 years as:

Nominal and High Adoption: from 0.5 to 0.

APPENDIX 5: SWITCH MODEL DATA DESCRIPTION FOR THE CALIFORNIA CARBON CHALLENGE

SWITCH was created at the University of California, Berkeley by Dr. Matthias Fripp (Fripp 2008, Fripp 2012). The version of SWITCH used in this study is maintained and developed by Ph.D. students James Nelson, Ana Mileva, and Josiah Johnston in Professor Daniel Kammen's Renewable and Appropriate Energy Laboratory at the University of California, Berkeley.

SWITCH Model Description

1. Study Years, Months, Dates and Hours

To simulate power system dynamics in WECC over the course of the next forty years, four levels of temporal resolution are employed by the SWITCH model: investment periods, months, days and hours. For this study, a single investment period contains historical data from 12 months, two days per month and six hours per day. There are four ten-year long investment periods: 2015-2025, 2025-2035, 2035-2045, and 2045-2055 in each optimization, resulting in (4 investment periods) x (12 months/investment period) x (2 days/month) x (6 hours/day) = 576 study hours over which the system is dispatched. The middle of each period is taken to represent the conditions within that period, e.g. results presented in this report for the year 2050 originate directly from the 2045-2055 investment period.

The peak and median day from each historical month are sampled to represent a large range of possible load and weather conditions over the course of each investment period. Each sampled day is assigned a weight: peak load days are given a weight of one day per month, while median days are given a weight of the number of days in a given month minus one. This weighting scheme ensures that the total number of days simulated in each investment period is equal to the number of days between the start and end of that investment period, emphasizes the economics of dispatching the system under 'average' load conditions, and forces the system to plan for capacity availability at times of high grid stress.

Weather conditions and the subsequent output of renewable generators dependent on these conditions can be correlated not only across renewable sites in space and time, but also correlated with electricity demand. A classic example of this type of correlation is the large magnitude of air conditioning load that is present on sunny, hot days. To include these correlations in SWITCH as much as possible, time-synchronized, historical hourly load and generation profiles for locations across WECC are employed. Dates in future investment periods correspond to a distinct historical date from 2006, for which historical data on hourly loads, simulated hourly wind capacity factors, and monthly hydroelectric availability over the Western United States, Western Canada, and Northern Baja Mexico are used. Solar capacity factors are calculated from hourly 2005 solar isolation data, as 2006 data was not available in the proper form. The day of year and hour of day is synchronized between the 2005 solar data and the 2006 wind and load data, thereby maintaining diurnal and seasonal correlations between load, wind, and solar. Hourly load data is scaled to projected future demand as is discussed in the description of the Base Case, Frozen Efficiency and Extra Electrification load profiles, while solar, wind and hydroelectric resource availability is used directly from historical data.

To make the optimization computationally feasible, each day is sampled every four hours, thereby including six distinct hours of load and resource data in each study date. For median days, hourly sampling begins at midnight Greenwich Mean Time (GMT) and includes hours 0, 4, 8, 12, 16, and 20. For peak days, hourly sampling is offset to ensure the peak hour is included, which may be at 14:00 Pacific Standard Time (PST) on some days and 15:00 PST on other days. These varying offsets can be seen upon close examination of hourly dispatch figures in the results section.

2. Important Indices

Important Sets and Indices		
Set	*Index*	*Description*
I	i	investment periods
M	m	months
D	d	dates
T	t	hours
$T_d \subset T$	--	set of all hours on date d
$T_i \subset T$	--	set of all hours in investment period i
A	a	load areas
LSE	lse	load-serving entities
BA	ba	balancing areas
F	f	fuel categories
$R \subset F$	r	set of RPS-eligible fuel categories
G	g	all generators
$C \subset G$	c	dispatchable generators
$VD \subset G$	vd	intermittent distributed generators
$VN \subset G$	vn	intermittent non-distributed generators
$B \subset G$	b	baseload generators
$S \subset G$	s	storage projects
$P \subset G$	p	pumped hydroelectric projects
$H \subset G$	h	non-pumped hydroelectric projects
G_a	--	set of generators in load area a

$\subset G$		
$C_a \subset C$	--	set of dispatchable generators in load area a
$VD_a \subset VD$	--	set of intermittent distributed generators in load area a
$VN_a \subset VN$	--	set of intermitted non-distributed generators in load area a
$B_a \subset B$	--	set of baseload generators in load area a
$S_a \subset S$	--	set of storage generators in load area a
$P_a \subset P$	--	set of pumped hydroelectric generators in load area a
$H_a \subset H$	--	set of hydroelectric generators in load area a
$G_{ba} \subset G$	--	set of generators in balancing area ba
$C_{ba} \subset C$	--	set of dispatchable generators in balancing area ba
$VD_{ba} \subset VD$	--	set of intermittent distributed generators in balancing area ba
$VN_{ba} \subset VN$	--	set of intermitted non-distributed generators in balancing area ba
$B_{ba} \subset B$	--	set of baseload generators in balancing area ba
$S_{ba} \subset S$	--	set of storage generators in balancing area ba
$P_{ba} \subset P$	--	set of pumped hydroelectric generators in balancing area ba
$H_{ba} \subset H$	--	set of hydroelectric generators in balancing area ba
$A_{lse} \subset A$	--	set of load areas in load-serving entity lse

3. Decision Variables: Capacity Investment

The model's first set of decision variables consists of the following infrastructure investment choices for the power system, which are made at the beginning of each ten-year investment period.

Capacity Investment Decision Variables:

1. Amount of new generation capacity to install of each generator type in each load area
2. Amount of transmission capacity to add between each pair of load areas
3. Whether to operate each existing power plant in each period

Investment Decision Variables	
$G_{g,i}$	Capacity installed in period i at plant g (further subdivided into generator types including dispatchable plants c, baseload plants b, storage plants s, hydroelectric plants h, and pumped hydroelectric plants p)
$CG_{c,i}$	Capacity installed in period i at dispatchable project c
$VDG_{vd,i}$	Capacity installed in period i at distributed intermittent project vd
$VNG_{vn,i}$	Capacity installed in period i at non-distributed intermittent project vn
$BG_{b,i}$	Capacity installed in period i at baseload project b
$T_{a,a',i}$	Capacity installed in period i between load area a and load area a'
$SG_{s,i}$	Capacity installed in period i at storage project s

Generation and storage projects can only be built if there is sufficient time to build the project between present day and the start of each investment period. This is only important for projects with long construction times such as nuclear plants and compressed air energy storage projects, which could not be finished by 2015, even if construction began today. Carbon Capture and Sequestration (CCS) generation cannot be built in the first investment period of 2015-2025, as this technology is not likely to be mature enough to able to be deployed at large (GW) scale before 2020. New nuclear plants must have a minimum capacity of 1 GW to reflect the minimum feasible nuclear plant size. Installation of resource-constrained generation and storage projects cannot exceed the maximum available resource for each project.

During each investment period, the model decides whether to operate or retire each of the ~800 existing power plants in WECC. All existing plants except for nuclear plants are forced to retire at the end of their operational lifetime. Nuclear plants can extend operation past their operational lifetime, but are required to pay operations and maintenance, as well as fuel costs for which any period in which they are operational. Hydroelectric facilities are required to operate throughout the whole study as, in addition to their value as electric generators, they also have much value in controlling stream flow.

New high-voltage transmission capacity is built along existing transmission corridors between the largest capacity substations of each load area. If no transmission corridor exists between two load areas, new transmission lines can be built at 1.5 times the straight-line transmission cost of $1000 MW^{-1}mi^{-1}, reflecting the difficulty of transmission siting and permitting.

Transmission can be built between adjacent load areas, non-adjacent load areas with primary substations less than 300 km from one another, and non-adjacent load areas that are already connected by existing transmission. Existing transmission links that are approximated well by two or more shorter links between load areas are removed from the new expansion decisions. Investment in transmission lines greater than 300 km in length is approximated by investment in a handful of shorter links.

Investment in new local transmission and distribution within a load area is included as a sunk cost and hence does not have associated decision variables.

4. Decision Variables: Dispatch

4.1. Generation Dispatch

The second set of decision variables includes choices made in every study hour about how to dispatch generation, storage, and transmission in order to meet load.

Dispatch Decision Variables:

1. Amount of power to generate from each dispatchable (hydroelectric or natural gas) generator in each load area in each hour
2. Amount of power to transfer along each transmission corridor in each hour
3. Amount of power to store and release at each storage facility (pumped hydroelectric, compressed air energy storage, and sodium-sulfur battery plant) in each hour

Hourly dispatch decisions are not made for baseload generators because this type of generator, if kept running in an investment period, is assumed to produce the same amount of power in each hour of that period. Hourly dispatch decisions are also not made for intermittent renewable generators such as wind and solar because renewable facilities produce an amount of power that is exogenously calculated: an hourly capacity factor is specified based on the weather conditions on the corresponding historical hour at the location of each renewable plant. Excess renewable generation can occur in any hour - the excess is simply curtailed.

Dispatch Decision Variables	
$O_{g,t}$	Energy output of plant g in hour t (further subdivided into generator types including dispatchable plants c, baseload plants b, storage plants s, hydroelectric plants h, and pumped hydroelectric plants p)
$C_{c,t}$	Energy dispatched in hour t from dispatchable project c
$Tr_{a,a',t}$	Power dispatched in hour t along the transmission line between load area a and load area a'
$S_{s,t,f}$	Energy stored in hour t of fuel category f at storage project s
$R_{s,t,f}$	Energy released in hour t of fuel category f from storage project s
$H_{h,t}$	Energy dispatched in hour t from non-pumped hydroelectric project h
$PH_{p,t,f}$	Watershed energy dispatched in hour t of fuel category f from pumped-hydroelectric

	project p
$PHD_{p,t,f}$	Stored energy dispatched in hour t of fuel category f from pumped-hydroelectric project p
$PHS_{p,t,f}$	Energy stored in hour t of fuel category f at pumped-hydroelectric project p
$SP_{g,t}$	Spinning reserve provided by thermal dispatchable generator g in hour t (variable used only for dispatchable generators c)
$Q_{g,t}$	Quickstart capacity provided by thermal dispatchable generator g in hour t (variable used only for dispatchable generators c)
$OP_{g,t}$	Operating reserve (spinning and quickstart) provided by hydroelectric (h), pumped hydroelectric (p), and storage (s) plants in hour t

4.2. Dispatch of Operating Reserves

Operating reserves in the WECC are currently determined by the 'Regional Reliability Standard to Address the Operating Reserve Requirement of the Western Interconnection,'[24] This standard dictates that contingency reserves must be at least: "the sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation." At least half of those reserves must be spinning. In practice, this has usually meant a spinning reserve requirement of 3 percent of load and a quickstart reserve requirement of 3 percent of load. Similarly, the WECC version of SWITCH holds a base operating reserve requirement of 6 percent of load in each study hour, half of which is spinning. In addition, 'variability' reserves equal to 5 percent of the wind and solar output in each hour are held to cover the additional uncertainty imposed by generation intermittency.

SWITCH's operating reserve requirement is based on the "3+5 rule" developed in the Western Wind and Solar Integration Study as one possible heuristic for determining reserve requirements that is "usable" to system operators (GE Energy 2010). The 3+5 rule means that spinning reserves equal to 3 percent of load and 5 percent of wind generation are held. When keeping this amount of reserves, the report found, at the study footprint level there were no conditions under which insufficient reserves were carried to meet the implied $3\Delta\sigma$ requirement for net load variability. For most conditions, a considerably higher amount of reserves were carried than necessary to meet the $3\Delta\sigma$ requirement. Performance did vary at the individual area level, so in the future customized reserve rules may be implemented for different areas.

The size of the entity responsible for providing balancing services is important both in terms of ability to meet the reserve requirement and the cost of doing so. The sharing of generation resources, load, and reserves through interconnection and market mechanisms is one of the least-cost methods for dealing with load variability. Multiple renewable integration studies have now also demonstrated the benefits of increased balancing area size (through consolidation or cooperation) in managing the variability of intermittent renewable output. At present, WECC operates as 39 balancing areas (GE Energy 2010), but in light of the large benefits of increased balancing area size, their functions will likely be consolidated in the future. The Western Wind and

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[24] Available at: http://www.nerc.com/files/BAL-STD-002-0.pdf.

Solar Integration Study assumes five regional balancing area in WECC for operating reserves – Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California – as their "statistical analysis showed, incorporating large amounts of intermittent renewable generation without consolidation of the smaller balancing areas in either a real or virtual sense could be difficult." Similarly, the WECC version of SWITCH assumes the primary NERC subregion as the balancing area in its optimization. Six balancing areas are modeled: Arizona-New Mexico (AZNMSNV), Rocky Mountain (RMPA), California (CA), Pacific Northwest (NWPP), Canada (NWPP Canada), and Mexico (MX).

Currently the model allows natural gas generators (including gas combustion turbines, combined-cycle natural gas plants, and stream turbine natural gas plants), hydro projects, and storage projects (including CAES, NaS batteries, and pumped hydro) to provide spinning and non-spinning reserves. It is assumed that natural gas generators back off from full load and operate with their valves partially closed when providing spinning reserves, so they incur a heat rate penalty, which is calculated from the generator's part-load efficiency curve (London Economics and Global Energy Decisions, 2007). Natural gas generators cannot provide more than their 10-min ramp rates in spinning reserves and must also be delivering useful energy when providing spinning reserves as backing off too far from full load quickly becomes uneconomical. Hydro projects are limited to providing no more than 20 percent of their turbine capacity as spinning reserves, in recognition of water availability limitations and possible environmental constraints on their ramp rates.

5. Objective Function and Economic Evaluation

The objective function includes the following system costs:

1. capital costs of existing and new power plants and storage projects
2. fixed operations and maintenance (O&M) costs incurred yearly by all active power plants and storage projects
3. variable costs incurred for each MWh produced by each plant, including variable O&M costs, fuel costs to produce electricity, and any carbon costs of greenhouse gas emissions
4. capital costs of new and existing transmission lines and distribution infrastructure
5. annual O&M costs of new and existing transmission lines and distribution infrastructure

Objective function: minimize the total cost of meeting load		
Generation and	Capital	$$\sum_{g,i} G_{g,i} \cdot c_{g,i}$$	The capital cost incurred for installing capacity at plant g in investment period i is calculated as the generator size in MW $G_{g,i}$ multiplied by the capital cost (including installation and connect costs) of that type of generator in \$2007 / MW $c_{g,i}$.

	Fixed O&M	$+ (ep_g + \sum_{g,i} G_{g,i}) \cdot x_{g,i}$	The fixed operation and maintenance costs paid for plant g in investment period i are calculated as the total generation capacity of the plant in MW (the pre-existing capacity ep_g at plant g plus the capacity installed in all investment periods i) multiplied by the recurring fixed costs associated with that type of generator in \$2007 / MW $x_{g,i}$.
	Variable	$+ \sum_{g,t} O_{g,t} \cdot (m_{g,t} + f_{g,t} + c_{g,t}) \cdot hs_t$ $+ \sum_{g,t} SP_{g,t} \cdot (spf_{g,t} + spc_{g,t}) \cdot hs_t$	The variable costs paid for operating plant g in time point t are calculated as the power output in MWh $O_{g,t}$ multiplied by the sum of the variable costs associated with that type of generator in \$2007 / MWh. The variable costs include maintenance $m_{g,t}$, fuel $f_{g,t}$, and a carbon cost $c_{g,t}$ (not included in this study), and are weighted by the number of hours each time point represents, hs_t. Variable costs also include the per unit fuel ($spf_{g,t}$) and carbon ($spc_{g,t}$) costs incurred by thermal dispatchable plants providing spinning reserve, $SP_{g,t}$.
Transmission	Capital	$+ \sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot t_{a,a',i}$	The cost of building or upgrading transmission lines between two load areas a and a' in investment period i is calculated as the product of the rated transfer capacity of the new lines in MW $T_{a,a',i}$, the length of the new line $l_{a,a'}$, and the area-adjusted per-km cost of building new transmission in \$2007 / MW $\cdot$ km $t_{a,a',i}$. Transmission can only be built between load areas that already are connected or that are adjacent to each other.
	O&M	$+ \sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot x_{a,a',i}$	The cost of maintaining new transmission lines between two load areas a and a' in investment period i is calculated as the product of the rated transfer capacity of the new lines in MW $T_{a,a',i}$, the length of the new line $l_{a,a'}$, and the area-adjusted per-km cost of maintaining new transmission in \$2007 / MW $\cdot$ km $x_{a,a',i}$.
Distribution		$+ \sum_{a,i} d_{a,i}$	The cost of upgrading local transmission and distribution within a load area a in investment period i is calculated as the cost of building and maintaining the upgrade in \$2007 / MW, $d_{a,i}$. No decision variables are associated with these costs.
Sunk		$+ s$	Sunk costs include capital payments for existing plants, existing transmission networks, and existing distribution networks.

Capital costs are amortized over the expected lifetime of each generator or transmission

line, and only those payments that occur during the length of the study – 2015 to 2055 – are included in the objective function. The present day capital cost of building each type of power plant or storage project is reduced via an exponential decay function using a capital cost declination rate (see the New Generators: Capital Costs section). The capital cost of each project is locked in at the first year of construction. Construction costs for power plants are tallied yearly, discounted to present value at the online year of the project, and then amortized over the operational lifetime of the project. The cost to connect new power plants to the grid is assumed to be incurred in the year before operation begins.

For optimization purposes, all costs during the study are discounted to a present-day value using a common real discount rate of 7% (White House Office of Management and Budget 2010), so that costs incurred later in the study have less impact than those incurred earlier. All costs are specified in real terms, indexed to the reference year 2007.

6. Constraints

The model includes five main sets of constraints: those that ensure that load is satisfied, those that maintain the capacity reserve margin, those that require that operating reserve be maintained, those that enforce Renewable Portfolio Standards (RPS), and those that impose a carbon cap.

The load-meeting constraints require that the power system is dispatched to meet load in every hour in every load area while providing the least expensive power based on expected generation, storage, and transmission availability. The nameplate capacity of these grid assets is de-rated by its forced outage rate to represent the amount of power generation capacity that is available on average in each hour of the study. Baseload generators are also de-rated by their scheduled outage rates.

The capacity reserve margin constraints require that the power system maintain a planning reserve margin at all times, i.e. that it would have sufficient capacity available to provide at least 15 percent extra power above load in every load area in every hour if all generators, storage projects and transmission lines are working properly. In calculating reserve margin, the outputs of these grid assets are therefore not de-rated by forced outage rates. SWITCH determines the reserve margin schedule concurrently with the load-satisfying dispatch schedule.

The operating reserve constraints ensure that an operating reserve equal to a percentage of load plus a percentage of intermittent generation is maintained in all hours, half of which must be spinning reserve.

The RPS constraints require that a certain percentage of load be met by renewable energy sources, consistent with state-based Renewable Portfolio Standards.

The carbon cap constraints limit the total amount of carbon emissions in each study period to a pre-defined level, e.g. 80% below 1990 carbon emissions levels for the investment period 2045-2055.

6.1. Load-Meeting Constraints

1. Natural gas dispatchable generators (combined cycle, combustion turbine, and steam turbine) can provide no more power, spinning reserve, and quickstart capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are therefore not included here. Spinning reserve can only be provided in hours when the plant is also producing useful generation and cannot exceed a pre-specified fraction of capacity.

$MAX\_DISPATCH_{c,t}$ $$C_{c,t} + SP_{c,t} + Q_{c,t} \leq (1 - o_c) \cdot \sum_i CG_{c,i}$$	For each dispatchable project c in every hour t, the expected amount of power $C_{c,t}$, spinning reserve $SP_{c,t}$, and quickstart capacity $Q_{c,t}$ supplied by the dispatchable generator in that hour cannot exceed the sum, de-rated by the generator's forced outage rate o_c, of generator capacities $CG_{c,i}$ installed at generator c in the current and preceding periods i. The operational generator lifetime limits the extent of the sum over i to only periods in which the generator would still be operational.

$MAX\_SPIN_{c,t}$ $$SP_{c,t} \leq \frac{spin\_frac_c}{1 - spin\_frac_c} \cdot C_{c,t}$$	For each dispatchable project c in every hour t, the spinning reserve $SP_{c,t}$ supplied by the dispatchable generator in that hour cannot exceed a pre-specified fraction of capacity. This constraint is tied to the amount actually dispatched $C_{c,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing useful generation.

2. Intermittent generators (solar and wind) produce the amount of power corresponding to their simulated historical power output in each hour, de-rated by their forced outage rate. Intermittent generation is broken into non-distributed and distributed for use in the conservation of energy constraints below. These constraints define the derived variables $VD_{vd,t}$ and $VN_{vn,t}$, and as such do not appear in the compiled mixed-integer linear program.

$DISTRIBUTED\_VAR\_GEN_{vd,t}$ $$VD_{vd,t} = cf_{vd,t} \cdot (1 - o_{vd}) \cdot \sum_i VDG_{vd,i}$$	For each distributed intermittent project vd in every hour t, the expected amount of power, $VD_{vd,t}$, produced by the dispatchable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vd}, of generator capacities $VDG_{vd,i}$ installed at generator vd in the current and preceding periods i, multiplied by the generator's capacity

	factor in hour t, $cf_{vd,t}$. The operational generator lifetime limits the extent of the sum over i to only periods in which the generator would still be operational.
$NON\_DISTRIBUTED\_VAR\_GEN_{vn,t}$ $$VN_{vn,t} = cf_{vn,t} \cdot (1 - o_{vn}) \cdot \sum_i VNG_{vn,i}$$	For each distributed intermittent project vn in every hour t, the expected amount of power, $VN_{vn,t}$, produced by the dispatchable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vn}, of generator capacities $VNG_{vn,i}$ installed at generator vn in the current and preceding periods i, multiplied by the generator's capacity factor in hour t, $cf_{vn,t}$. The operational generator lifetime limits the extent of the sum over i to only periods in which the generator would still be operational.

3. Baseload generators (nuclear, coal, geothermal, biomass solid, biogas and cogeneration) must produce an amount of power equal to their nameplate capacity, de-rated by their forced and scheduled outage rates. This constraint defines the derived variable $B_{b,t}$ and as such does not appear in the compiled mixed-integer linear program.

$BASELOAD\_GEN_{b,t}$ $$B_{b,t} = (1 - o_b) \cdot (1 - s_b) \cdot \sum_i BG_{b,i}$$	For every baseload project b and every hour t, the expected amount of power, $B_{b,a,t}$, produced by each baseload generator b in each hour t cannot exceed the sum, de-rated by the generator's forced outage rate o_b and scheduled outage rate s_b, of generator capacities $BG_{b,i}$ installed at generator b in the current and preceding periods i. The operational generator lifetime limits the extent of the sum over i to only periods in which the generator would still be operational.

4. The amount of energy produced from all non-pumped hydroelectric facilities in a load area must equal or exceed 50% of the average non-pumped hydroelectric energy production for that load area in each hour, in order to maintain downstream water flow. The total amount of energy produced in each hour, on a load area basis, from all pumped and non-pumped hydroelectric facilities within a load area cannot exceed the load area's total turbine capacity, de-rated by the forced outage rate for hydroelectric generators.

$HYDRO\_MIN\_DISP_{h,t}$ $$H_{h,t} \geq ah_{h,m_t} \cdot mf$$	For every non-pumped hydroelectric project h in every hour t, the amount of energy $H_{h,t}$ dispatched by the non-pumped hydroelectric project must be greater than or equal to a pre-specified average flow rate for that project on the day of that hour, $ah_{h,m}$, times a pre-specified minimum dispatch fraction, mf, necessary to maintain stream flow.

$HYDRO\_MAX\_DISP_{h,t}$ $H_{h,t} + OP_{h,t} \leq (1 - o_h) \cdot hg_h$	For every non-pumped hydroelectric project h in every hour t, the amount of energy $H_{h,t}$ and operating reserve $OP_{h,t}$ dispatched by the non-pumped hydroelectric project h cannot exceed the project's capacity, hg_h de-rated by the hydroelectric project's forced outage rate o_h.

$HYDRO\_MAX\_RESERVE_{h,t}$ $OP_{h,t} \leq hydro\_op\_fraction \cdot hg_h$	For every hydroelectric project h in every hour t, the amount of operating reserve $OP_{h,t}$ dispatched cannot exceed a fraction $hydro\_op\_fraction$ of the project's capacity, hg_h.

$PUMPED\_HYDRO\_MAX\_DISP_{p,t}$ $PH_{p,t} + \sum_f PHD_{p,t,f} + OP_{p,t} \leq (1 - o_p) \cdot pg_p$	For pumped hydroelectric project p and every hour t, the sum of watershed energy, $PH_{p,t,f}$, dispatched stored energy, $PHD_{p,t,f}$, from all fuel categories f, and operating reserve $OP_{p,t}$ cannot exceed the pre-specified capacity of the pumped hydroelectric project, pg_p, de-rated by the pumped hydroelectric project's forced outage rate o_p.

5. The amount of energy produced from all hydroelectric facilities in a load area over the course of each study day must equal the historical average energy production for the month in which that day resides.

$HYDRO\_AVG\_OUTPUT_{h,t}$ $\sum_{t \in T_d} H_{h,t} = \sum_{t \in T_d} ah_{h,m_t}$	For every non-pumped hydroelectric project h and every day d, the historical monthly average flow must be met, i.e. the sum over all hours on day d of energy, $H_{h,t}$, dispatched by the non-pumped hydroelectric project p must equal a pre-specified average daily level $ah_{h,m}$ for that month. T_d is the set of hours on day d.

$PUMPED\_HYDRO\_AVG\_WATERSHED_{p,d}$	For every pumped hydroelectric project p and every day d, $PH_{p,t,f}$, the total watershed energy released by the pumped-hydroelectric project, must equal a pre-specified average daily level $ah_{h,m}$, for that month. T_d is the set of hours on day

$$\sum_{t \in T_d} PH_{p,t} = \sum_{t \in T_d} ah_{h,m_t}$$	d.

6. A storage project can store no more power in each hour than its maximum hourly store rate, de-rated by its forced outage rate, and dispatch no more power in each hour than its capacity, de-rated by its forced outage rate. Compressed Air Energy Storage (CAES) projects must maintain the proper ratio between energy stored in the form of compressed air and energy dispatched in the form of natural gas.

MAX_STORAGE_RATE$_{s,t}$ $$\sum_f S_{s,t,f} \le (1-o_s) \cdot r_s \cdot \sum_i SG_{s,i}$$	For every storage project s in every hour t, the expected amount of energy, $S_{s,t,f}$, stored at the storage project s in hour t from each fuel type f cannot exceed the product of a pre-specified store rate for that project, r_s, and the total capacity $SG_{s,t,f}$ installed at project s in the current and preceding periods i, de-rated by the storage project's forced outage rate o_s. The operational storage project lifetime limits the extent of the sum over i to only periods in which the storage project would still be operational.

MAX_STORAGE _DISPATCH$_{s \ne CAES,t}$ $$\sum_f R_{s,t,f} + OP_{s,t} \le (1-o_s) \cdot \sum_i SG_{s,i}$$	For every non-CAES storage project s in every hour t, the expected amount of energy dispatched from the storage project in that hour from all fuel types f, $R_{s,t,f}$, plus the operating reserve provided $OP_{s,t}$ in that hour cannot exceed the sum, de-rated by the storage project's forced outage rate o_s, of the storage project power capacity $SG_{s,i}$ installed in the current and preceding periods i. The operational storage project lifetime limits the extent of the sum over i to only periods in which the storage project would still be operational.

MAX_CAES _DISPATCH$_{s=CAES,t}$ $$\sum_f R_{s,t,f} + C_{s,t} + SP_{s,t} + Q_{s,t} + OP_{s,t}$$ $$\le (1-o_s) \cdot \sum_i SG_{s,i}$$	For every CAES storage project s in every hour t, the sum of the energy dispatched from all fuel types f, $R_{s,t,f}$, and the operating reserve $OP_{s,t}$ provided by the storage plant plus the energy dispatched $C_{s,t}$, spinning reserve $SP_{s,t}$ and quickstart reserve $Q_{s,t}$ provided from natural gas cannot exceed the sum, de-rated by the plant's forced outage rate o_s, of the plant's total power capacity $SG_{s,i}$ installed in the current and preceding periods i. The operational CAES project lifetime limits the extent of the sum over i to only periods in which the CAES project would still be

	operational.
CAES_COMBINED_DISPATCH$_{s=CAES,t}$ $$\sum_f R_{s,t,f} = C_{s,t} \cdot caes\_ratio$$	For every CAES project s in every hour t, the amount of energy dispatched from the CAES project in that hour from all fuel types f, $R_{s,t,f}$, must equal the amount of energy dispatched from natural gas $C_{s,t}$ multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

CAES_COMBINED_OR$_{s=CAES,t}$ $$OR_{s,t} = (SP_{s,t} + Q_{s,t}) \cdot caes\_ratio$$	For every CAES project s in every hour t, the amount of operating reserve dispatched from the CAES project in that hour must equal the operating reserve (spinning plus quickstart) dispatched from natural gas ($SP_{s,t}$+ $Q_{s,t}$) multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

PUMPED_HYDRO_MAX_STORE$_{p,t}$ $$\sum_f PHS_{p,t,f} \le pg_p \cdot (1 - o_p)$$	For every hour t, the energy stored by a pumped hydroelectric project p, $PHS_{p,t,f}$, cannot exceed the pre-specified capacity of the hydroelectric project, de-rated for the project's forced outage rate o_p.

7. Because days are modeled as independent dispatch units, the energy dispatched by each storage project each day must equal the energy stored by the project on that day, adjusted for the storage project's round-trip efficiency losses.

STORAGE_ENERGY_BALANCE_BY_FUEL_CATEGORY$_{s,d,f}$ $$\sum_{t \in T_d} R_{s,t,f} = \sum_{t \in T_d} S_{s,t,f} \cdot e_s$$	For each storage project s and each fuel category f on each day d, the energy from fuel category f dispatched by the storage project in all hours t on day d must equal the energy stored by the storage project in all hours t on day d, de-rated by the storage project's round-trip efficiency e_s.

STORAGE_ENERGY_BALANCE$_{s,d}$ $$\sum_{t \in T_d} R_{s,t} + op\_fraction \cdot \sum_{t \in T_d} OR_{s,t} = \sum_{t \in T_d} S_{s,t} \cdot e_s$$	For each storage project *s* on each day *d*, the energy dispatched by the storage project in all hours *t* on day *d* must equal the energy stored by the storage project in all hours *t* on day *d*, de-rated by the storage project's round-trip efficiency e_s. It is assumed that operating reserve is called upon to produce energy a fraction of the time, *op_fraction*, and this is included in the energy balance. T_d is the set of hours on day *d*.

PUMPED_HYDRO_ENERGY_BALANCE_BY_FUEL_CATEGORY$_{p,d,f}$ $$\sum_{t \in T_d} PHD_{p,t,f} = \sum_{t \in T_d} PHS_{p,t,f} \cdot pe$$	For every pumped hydroelectric project *p*, every day *d*, and every fuel category, $PHD_{p,t,f}$, the total amount of energy from fuel type *f* dispatched by the project in all hours *t* on day *d*, must equal $PHS_{p,t,f}$, the total amount of energy from fuel type f stored by the hydroelectric project in all hours t on day d, times a pre-specified pumped hydroelectric storage efficiency, *pe*. T_d is the set of hours on day *d*.

PUMPED_HYDRO_ENERGY_BALANCE$_{p,d}$ $$\sum_{t \in T_d} PHD_{p,t,f} + op\_fraction \cdot \sum_{t \in T_d} OP_{p,t,f} = \sum_{t \in T_d} PHS_{p,t,f} \cdot pe$$	For every pumped hydroelectric project *p*, every day *d*, the total amount of energy $PHD_{p,t}$ dispatched by the hydroelectric project in all hours *t* on day *d*, must equal $PHS_{p,t,f}$, the total amount of energy stored by the hydroelectric project in all hours t on day d, times a pre-specified pumped hydroelectric storage efficiency, *pe*. It is assumed that operating reserve is dispatched a fraction of the time, *op_fraction*, and this is included in the energy balance. T_d is the set of hours on day *d*.

8. The amount of power transferred in each direction through transmission lines in each hour

between each pair of connected load areas can be no more than the line's rated capacity, de-rated by its forced outage rate. Once a transmission line is installed, it is assumed to remain in operation for the remainder of the study.

$MAX\_TRANS_{a,a1,t}$ $$\sum_f Tr_{a,a',t,f} \leq (1 - o_{a,a'}) \cdot \left(et_{a,a'} + \sum_i T_{a,a',i} \right)$$	For each transmission line *(a, a')* in every hour *t*, the total amount of energy, $Tr_{a,a',t,f}$ from all fuel types *f* dispatched along the transmission line between load areas *a* and *a'* in each hour *t* cannot exceed the sum, de-rated by the transmission line's forced outage rate $o_{(a,a')}$, of the pre-existing transfer capacity $et_{(a,a')}$ and the sum of additional capacities $T_{a,a',i}$ installed between the two load areas in the current and all preceding periods *i*.

9. The total amount of power exported from the Mexican load area of Baja California Norte in each investment period cannot grow at more than of the historical electric power export growth rate between 2003 and 2008 of 3.2 %/yr (Secretaría de Energía 2010). This constraint ensures that Mexico can export power to United States load areas, but restricts the growth of exports to realistic levels.

$MEX\_EXPORT\_LIMIT_{a=MEX\_BAJA,i}$ $$\sum_{a',t\in T_i,f} Tr_{a,a',t,f} \cdot hs_t - \sum_{a'',t\in T_i,f} Tr_{a'',a,t,f} \cdot hs_t \leq mexptlim_i$$	For each investment period *i*, the sum of transmission capacity $Tr_{a,a',t,f}$ dispatched out of the load area *a=MEX_BAJA*, minus the sum of transmission capacity $Tr_{a'',a,t,f}$ dispatched into the load area *a=MEX_BAJA*, weighted by the number of sample hours hs_t represented by timepoint *t*, cannot exceed the specified export limit out of MEX_BAJA $mexptlim_i$.

10. The total expected supply of power from generation, storage, and transmission in each load area during each hour must equal or exceed the amount of power consumed in that load area and at that time. The total supply of power can exceed the demand for power to reflect the potential of spilling power or curtailment during certain hours.

$CONSERVATION\_OF\_ENERGY\_NON\_DISTRIBUTED_{a,t,f}$	For every load area *a*, in each hour *t*, and for

	$NP_{a,t,f} \cdot (1 + dl) \leq$	every fuel category f, the amount of non-distributed energy $NP_{a,t,f}$ consumed in the load area in that hour plus any distribution losses dl cannot exceed
Generation	$\displaystyle\sum_{vn \in VN_a} VN_{vn,t,f} + \sum_{c \in C_a} C_{c,t,f} + \sum_{b \in B_a} B_{b,t,f} + \sum_{h \in H_a} H_{h,t,f} +$	the total power generated in load area a in hour t by all intermittent non-distributed projects ($VN_{vn,t,f}$), all baseload projects ($B_{b,t,f}$), all dispatchable projects ($C_{c,t,f}$), and all non-pumped hydroelectric generators ($H_{h,t,f}$)
Transmission	$\displaystyle + \sum_{a,a'} Tr_{a,a',t,f} \cdot e_{a,a'} - \sum_{a'',a} Tr_{a'',a} +$	plus the total power supplied to load area a from other load areas a' via transmission, de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power exported from load area a to other load areas a'' via transmission
Storage	$\displaystyle + \sum_{s \in S_a} R_{s,t,f} - \sum_{s \in S_a} S_{s,t,f} +$	plus the total energy, $R_{s,t,f}$, supplied to load area a in hour t by storage projects s minus the total energy, $S_{s,t,f}$, that is stored by storage projects s
Pumped Hydroelectric	$\displaystyle + \sum_{p \in P_a} PH_{p,t,f} + \sum_{p \in P_a} PHD_{p,t,f} - \sum_{p \in P_a} PHS_{p,t,f}$	plus the total power generated from pumped hydroelectric watershed energy, $PH_{p,a,t}$, and the total power dispatched from pumped hydroelectric storage, $PHD_{p,a,t,f}$, that is supplied to load area a in hour t by all pumped hydroelectric projects p, minus the total power, $PHS_{p,a,t,f}$, that is stored by pumped hydroelectric projects p in load area a in hour t.
Redirected	$+ DR_{a,t,f}$	plus distributed energy , $DR_{a,t,f}$, that is exported through the distribution system to the transmission grid.

CONSERVATION_OF_ENERGY_DISTRIBUTED$_{a,t,f}$ $DP_{a,t,f} + DR_{a,t,f} \cdot (1 + dl) \geq$ $\sum\limits_{vd \in VD_{a,f}} VD_{vd,t}$	In every load area *a*, in each hour *t*, and for every fuel category *f*, the amount of distributed energy $DP_{a,t,f}$ consumed in the load area plus any distributed power, $DR_{a,t,f}$, that is exported through the distribution system, adjusted for distribution losses *dl*, cannot exceed the total distributed generation available in load area *a* in hour *t*.

SATISFY_LOAD$_{a,t}$ $\sum\limits_{f} (NP_{a,t,f} + DP_{a,t,f}) = l_{a,t}$	For every load area *a* in each hour *t*, the total energy consumed from distributed and non-distributed sources must equal the pre-defined system load $l_{a,t}$.

6.2. Reserve-Margin constraints

Power plants and transmission lines can experience outages and various mechanical failures, To address system risk, the model requires that enough power plant and transmission capacity be built to provide a 15% capacity reserve margin above load in each load area in all hours.

1. The total supply of reserve capacity in each load area during each hour must equal or exceed 115% of the power demand in each load area and in each study hour.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED_RESERVE$_{a,t}$ $NPR_{a,t} \cdot (1 + dl) \leq$	In every load area *a*, in each hour *t*, the amount of non-distributed capacity $NPR_{a,f}$ available to meet the capacity reserve margin in the load area in that hour plus any distribution losses *dl* cannot exceed
Generation Capacity $\sum\limits_{vn \in VN_a} (cf_{vn,t} \cdot \sum\limits_{i} VNG_{vn,i})$ $+ \sum\limits_{c \in C_a} \sum\limits_{i} CG_{c,i}$ $+ \sum\limits_{b \in B_a} \sum\limits_{i} BG_{b,i} \cdot (1 - s_b)$	the total capacity of all intermittent non-distributed projects ($VNG_{vn,i}$) multiplied by their capacity factor $cf_{vn,t}$ in hour t, plus the total capacity of all dispatchable projects ($CG_{c,i}$), plus the total capacity, adjusted for scheduled outage rate s_b, of all baseload projects ($B_{b,i}$) in load area *a* in hour *t*,

Transmission Capacity	$+\sum_{a,a'}\sum_{f}Tr_{a,a',t,f}\cdot e_{a,a'}-\sum_{a'',a}\sum_{f}Tr_{a'',a,t,f}$	plus the total power transmitted to load area a from other load areas a' ($Tr_{a,a',t,f}$), de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power transmitted from load area a to other load areas a'' ($Tr_{a'',a,t,f}$)
Storage Capacity	$+\sum_{s\in S_a}\sum_{f}R_{s,t,f}-\sum_{s\in S_a}\sum_{f}S_{s,t,f}$	plus the total output $R_{s,t,f}$, of storage projects s in load area a in hour t minus the energy stored, $S_{s,t,f}$, by storage projects s in load area a in hour t
Hydroelectric and Pumped Hydroelectric Capacity	$+\sum_{h\in H_a}H_{h,t}+\sum_{p\in P_a}PH_{p,t}$ $+\sum_{p\in P_a}\sum_{f}PHD_{p,t,f}-\sum_{p\in P_a}\sum_{f}PHS_{p,t,f}$	plus the total non-pumped hydroelectric ($H_{h,t}$) and pumped hydroelectric ($PHR_{p,a,t}$) watershed power supplied, and the total pumped hydroelectric stored power, $PHD_{p,a,t,f}$, supplied to load area a in hour t by all pumped hydroelectric projects p minus the total energy, $PHS_{p,a,t,f}$, that is stored by pumped hydroelectric projects p.
Redirected	$+DRR_{a,t}$	plus the distributed capacity, $DRR_{a,t}$, that is available to be exported through the distribution system.

$CONSERVATION\_OF\_ENERGY\_DISTRIBUTED\_RESERVE_{a,t,f}$ $DPR_{a,t}+DRR_{a,t}\cdot(1+dl)\geq$ $\sum_{vn\in VN_a}(cf_{vd,t}\cdot\sum_{i}VDG_{vd,i})$	In every load area a, in each hour t, the amount of distributed energy $DPR_{a,t}$ consumed in the load area plus any distributed power, $DRR_{a,t}$, adjusted for distribution losses dl, that is exported through the distribution system cannot exceed the total distributed generation capacity available in load area a in hour t.

$SATISFY\_RESERVE\_MARGIN_{a,t}$ $DPR_{a,t}+NPR_{a,t}=$ $(1+r)\cdot l_{a,t}$	For each load area a, in each hour t, the total distributed and non-distributed capacity available for consumption must equal the pre-defined system load $l_{a,t}$ for that load area for that hour plus a pre-specified reserve margin r.

6.4. Operating Reserve Constraints

$SATISFY\_SPINNING\_RESERVE_{ba,t}$ $$\sum_{c \in C_{ba}} SP_{c,t} + \sum_{g \in S_{ba} \cup H_{ba} \cup P_{ba}} OP_{g,t}$$ $$\geq spinning\_reserve\_reqt_{ba,t}$$	In each balancing area *ba* in each hour *t*, the spinning reserve provided by dispatchable plants, $SP_{c,t}$, plus the operating reserve $OP_{g,t}$ provided by storage plants ($g \in S_a$), hydroelectric plants ($g \in H_a$), and pumped hydroelectric storage plants ($g \in P_a$) must equal or exceed the spinning reserve requirement in that balancing area in that hour. The spinning reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

$SATISFY\_OPERATING\_RESERVE_{ba,t}$ $$\sum_{c \in C_{ba}} SP_{c,t} + \sum_{c \in C_{ba}} Q_{c,t} + \sum_{g \in S_{ba} \cup H_{ba} \cup P_{ba}} OP_{g,t}$$ $$\geq operating\_reserve\_reqt_{ba,t}$$	In each balancing area *ba* in each hour *t*, the spinning reserve provided by dispatchable plants, $SP_{c,t}$, plus the quickstart reserve provided by dispatchable plants, $Q_{c,t}$, plus the operating reserve $OP_{g,t}$ provided by storage plants ($g \in S_a$), hydroelectric plants ($g \in H_a$), and pumped hydroelectric storage plants ($g \in P_a$) must equal or exceed the total operating reserve requirement (spinning plus quickstart) in that balancing area in that hour. The operating reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

6.5. RPS Constraint

This constraint requires that, for each load-serving entity and for every period, the percentage of total consumed power delivered by qualifying renewable sources is greater than or equal to the fraction specified by existing RPS targets. The RPS constraint does not allow the use of unbundled, tradable Renewable Energy Credits (RECs).

$MEET\_RPS_{lse,i}$ $$\frac{\sum_{t \in T_i, f \in R, a \subset A_{lse}} (DP_{a,t,f} + NP_{a,t,f}) \cdot hs_t}{\sum_{t \in T_i, a \subset A_{lse}} l_{a,t} \cdot hs_t} \geq rps_{lse,i}$$	For every load-serving entity *lse* in every period *i*, the proportion of the total power consumed in all hours of that period (the set T_i) from all RPS-eligible fuels (the set R) must be greater than or equal to the pre-defined RPS fraction, $rps_{lse,i}$, for that load area for that period. Each timepoint in the set T_i is weighted by the number of sample hours it represents, hs_t.

6.5. Carbon Cap Constraint

This constraint requires that, for every period, the total carbon dioxide emissions from generation and spinning reserve provision cannot exceed a pre-specified emissions cap.

$CARBON\_CAP_i$ $$\sum_{g,t \in T_i} O_{g,t} \cdot hr_g \cdot co2\_fuel_g$$ $$+ \sum_{c,t \in T_i} SP_{c,t} \cdot hr\_penalty_g \cdot co2\_fuel_g$$ $$\leq carbon\_cap_i$$	In every period i, the total carbon emissions from generation (calculated as the plant output $O_{g,t}$ times the plant heat rate hr_g times the carbon dioxide fuel content for that plant) plus the carbon emissions from spinning reserve (calculated as the plant output $O_{g,t}$ times the plant per unit heat rate penalty for providing spinning reserve $hr\_penalty_g$ times the carbon dioxide fuel content for that plant) cannot exceed a pre-specified carbon cap $carbon\_cap_i$ for that period.

Data Description

1. Load Areas: Geospatial Definition

The model divides the geographic region of WECC into 50 load areas. These areas represent sections of the grid within which there is significant existing local transmission and distribution, but between which there is limited long range, high-voltage existing transmission. Consequently, load areas are areas between which transmission investment may be beneficial.

Load areas are predominantly divided according to pre-existing administrative and geographic boundaries, including, in descending order of importance, state lines, North American Electric Reliability Corporation (NERC) control areas and utility service territory boundaries. Utility service territory boundaries are used instead of state lines where much high-voltage transmission connectivity is present between states within the same utility service territory. The location of mountain ranges is considered because of their role as natural boundaries to transmission networks. Major metropolitan areas are included because they represent localized areas of high electrical demand.

In addition, load area boundaries are defined to capture as many currently congested transmission corridors as possible (Western Electricity Coordinating Council 2009). These pathways are some of the first places that transmission is likely to be built, and exclusion of these pathways in definition of load areas would allow power to flow without penalty along overloaded transmission lines.

2. Cost Regionalization

Costs for constructing and operating generation and transmission vary significantly by region. To capture this variation, all costs in the model are multiplied by a regional economic multiplier derived from normalized average pay for major occupations in United States Metropolitan Statistical Areas (MSAs) (United States Department of Labor 2009). Counties that are not present in the listed MSAs are given the regional economic multiplier of the nearest MSA. These regional economic multipliers are then assigned to load areas weighted by the population within each county located within each load area.

Data for Canadian and Mexican economic multipliers are estimated and will be updated in future versions of the model.

3. Transmission Lines

The existing transmission capacity between load areas is found by matching geolocated Ventyx data (Ventyx EV Energy Map) with Federal Energy Regulatory Commission (FERC) data on the thermal limits of individual power lines (Federal Energy Regulatory Commission 2009). A small fraction of lines present in the Ventyx database could not be matched to lines found in the FERC database; these lines are ascribed a generic transfer capacity equal to the average transfer capacity of their voltage class. In total, 104 existing inter-load-area transmission corridors are represented in SWITCH.

The largest capacity substation in each load area is chosen by adding the transfer capacities of all lines into and out of each substation within each load area. It is assumed that all power transfer between load areas occurs between these largest capacity substations, using the corresponding distances along existing transmission lines between these substations. If no existing path is present, new transmission can be installed between adjacent load areas assuming a distance of 1.5 the distance between largest capacity substations of the two load areas.

The amount of power that can be transferred along each transmission line is set at the rated thermal limits of individual transmission lines. Additionally, transmission power losses are taken into account at 1 percent of power is lost for every 100 miles over which it is transmitted, with an upper limit of 98.5 % efficiency between any pair of load areas.

4. Local T&D and Transmission Costs

The costs for existing transmission and distribution are derived from the regional electricity tables of the United States Energy Information Agency's 2010 Annual Energy Outlook (United States Energy Information Agency 2010a). The $/MWh cost incurred in 2010 for each NERC subregion is apportioned by present day average load to each load area and is then assumed to be a sunk cost over the whole period of study. All existing transmission and distribution capacity is therefore implicitly assumed to be kept operational indefinitely, incurring concomitant operational costs.

It is further assumed that the distribution network is built to serve the peak load of 2011, and that in future investment periods this equivalence must be maintained. Investment in new local transmission and distribution is therefore a sunk cost as projected loads are exogenously calculated.

Distribution losses are assumed to be 5.3% of end-use demand; commercial and residential distributed PV technologies are assumed to experience zero distribution losses as they are sited inside the distribution network. In the case of surplus distributed generation, the model can send power from distributed generators out to other load areas, incurring a 5.3% power loss on the way out. This loss is in addition to subsequent transmission, storage and distribution losses, so power sent in this manner will incur distribution losses twice.

5. Load Profiles

Planning Area hourly loads from the Federal Energy Regulatory Commission's (FERC) Annual Electric Balancing Authority Area and Planning Area Report (FERC Form 714) (Federal Energy Regulatory Commission 2006) are partitioned into SWITCH load areas by manually matching substations owned by each planning area to georeferenced substations (Platts Corporation 2009). As not all substations match between the two datasets, a map of each planning area is created by drawing boundaries around each of the substation areas. Existing geospatial layers of planning areas from Platts (Platts Corporation 2009) and Ventyx (Ventyx EV Energy Map) do not provide enough data to be used exclusively in this process because of overlapping territories, changes in planning areas over time, and the complexity of the electric power system at the distribution level. Rather, these planning area layers serve only as a guide to forming maps of planning area loads.

Many load areas are comprised of encompass single planning areas; for these regions, the planning area hourly load is used as the load of the corresponding load area. For planning areas that cross load area boundaries, the fraction of population within each load area is used to apportion planning area loads between SWITCH load areas. Finally, as the planning areas PacificCorp and Bonneville Power Administration span the Western and Central time zones but report a single hourly load, loads from areas located within these LSEs but in a different time zone from the reported load are shifted one hour to reflect the difference in timing of loads as a function of the hour of day.

Load on each hour in the model corresponds to the observed load on one historical hour from the year 2006. These hourly loads are then shaped using hourly load profiles for energy efficiency, electrification of heating, and electric vehicles. The magnitude of load added (or subtracted in the case of energy efficiency) to the 2006 load profile is dictated by electricity load projections discussed in the body of this report.

Hourly California load projections for energy efficiency and electrification of heating from present day to 2050 from were obtained from Itron for each of the three load profile cases (Frozen Efficiency, Base Case and Extra Electrification). These projections are made for each California forecast climate zone and are divided into load areas via the population fraction of each climate zone in each load area. For load areas outside California, the load profiles across all of California for energy efficiency and electrification of heating were used to shape demand. California load profiles were time-shifted by one hour for load areas in Mountain time to reflect dependence on the hour of day. In addition, as the adoption of heating electrification is assumed to occur ten years later in the rest of WECC than it does in California, the California heating electrification load profile was shifted ten years back when applied to load areas outside California.

Hourly electric vehicle loads are created from a daily charging profile shown below provided by UC Davis and scaled to projected demands. Historical monthly demand is also used to shape the magnitude of electric vehicle demand in each month.
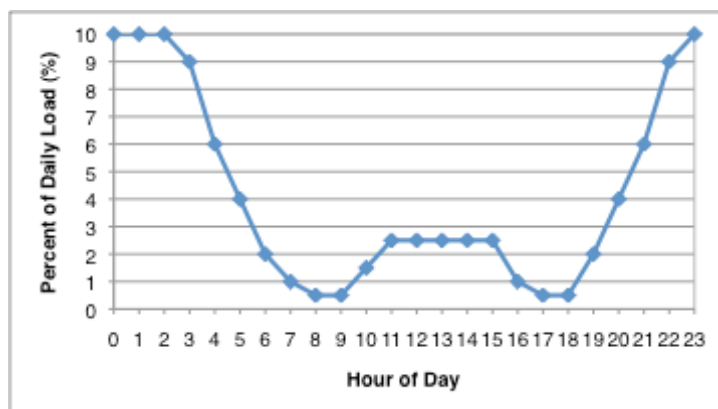
Appendix Figure 1: *Electric Vehicle daily charging profile.*

6. Renewable Portfolio Standards

State-based Renewable Portfolio Standards (RPS) specify that a certain fraction of electricity consumed within a Load Serving Entity (LSE) that must be produced by qualified renewable generators. Targets follow a yearly schedule, increasing from low levels presently higher levels by the mid 2020s (North Carolina State University 2011). For example, California has RPS targets of 20% and 33% by 2010 and 2020, respectively. RPS targets are subject to the political structure of each state and are therefore heterogeneous in not only what resources qualify as renewable, but also when, where and how the qualifying renewable power is made and delivered. To maintain computational feasibility, RPS is modeled as a yearly target for each load area for the percentage of load that must be met by *delivered renewable* power.

In the version of SWITCH used in this study, renewable power is defined as power from geothermal, biomass solid, biomass liquid, biogas, solar or wind power plants. This is consistent with most of the state-specific definitions of qualifying resources in the western United States. Additionally, in most states, large hydroelectric power plants (> 50 MW) are not considered renewable power plants due to their high environmental impacts. Small hydroelectric power plants (< 50 MW) do not qualify as renewable power in the current version of the model.

Delivered power is power that is either generated within a load area and consumed immediately, or added to the power mix of the load area via transmission or storage, after accounting for efficiency losses. Power lost during distribution is not counted towards RPS targets. To ensure proper accounting, the stocks and flows of qualifying power is kept separate from non-qualifying power.

While most load areas are fully contained within a single LSE and a single state, targets for those load areas that span LSE and/or state lines are calculated as a weighted sum of the RPS goals on the two sides of the LSE and/or state border, with the weights based on the relative population

levels within each load area within each LSE and/or state. RPS targets are averaged over each period for each load area. Canadian and Mexican load areas do not have RPS targets.

7. Fuel Prices

Coal, natural gas and fuel oil fuel price projections for electric power generation originate from the reference case of the United States Energy Information Agency's 2011 Annual Energy Outlook (United States Energy Information Agency 2011). These yearly projections are made for each North American Electric Reliability Corporation (NERC) subregion through 2035, and are extrapolated for years after 2035. Yearly fuel price projections are averaged over each study period. The fuel price for each load area is set by the NERC subregion with the greatest overlap with that load area. Canadian and Mexican coal, natural gas and fuel oil prices are assumed to be the same as the prices in the nearest United States NERC subregion. Fuel price elasticity is not currently included.

Uranium price projections are taken from the California Energy Commission's 2007 Cost of Generation Model (Klein 2007). These prices apply to all load areas as uranium has less regional price variation than other fuels.

Solid biomass fuel costs are discussed directly below.

8. Biomass Supply Curve

Fuel costs for solid biomass are input into the model as a piecewise linear supply curve for each load area. This piecewise linear supply curve is adjusted to include producer surplus from the solid biomass cost supply curve in order to represent market equilibrium of biomass prices in the electric power sector.

As no single data source is exhaustive in the types of biomass considered, solid biomass feedstock recovery costs and corresponding energy availability at each cost level originate from a variety of sources listed in the table below. This table does not represent the technical potential of recoverable solid biomass – instead it depicts the economically recoverable quantity of biomass solid feedstock. The definition of 'economically recoverable' is dependent on each dataset, but the maximum cost is generally less than or equal to $100 per bone dry ton (BDT) of biomass. Feedstock prices range between $0.2/MMBtu and $13.3/MMBtu (in $2007), with a quantity-weighted average price across WECC of $2.7/MMBtu. While the energy content per BDT of biomass varies by feedstock, a factor of 15 MMBtu/BDT can be used for rough conversion between BDT and MMBtu. Note that, following standard biomass unit definitions, 1 MMBtu = 10^6 Btu.

Biomass Feedstock Type	California Availability [10^{12} Btu/Yr]	Rest of WECC Availability [10^{12} Btu/Yr]	California Availability [10^{12} BDT/Yr]	Rest of WECC Availability [10^{12} BDT/Yr]	Sources
Corn Stover	19.1	82.3	1.35	5.83	1
Forest Residue	41.3	408.8	2.74	27.13	1, 4
Forest Thinning	72.3	211.0	4.80	14.00	1
Mill Residue + Pulpwood	39.5	254.3	2.62	16.87	2, 3, 4
Municipal Solid Waste (MSW)	81.4	117.1	4.93	7.10	2, 4
Orchard and Vineyard Waste	66.1	10.5	4.39	0.70	2
Switchgrass	0	123.7	0	8.43	1, 4
Wheat Straw	8.1	70.0	0.60	5.16	1
Agricultural Residues (Canada Data Only)	0	183.2	0	13.51	4
Total	**327.8**	**1460.9**	**21.43**	**98.73**	

Appendix Table 1: *Biomass Supply in the SWITCH model for years 2030 and beyond. Sources: 1: de la Torre Ugarte 2000; University of Tennessee 2007; 2: Parker 2011; 3: Milbrandt 2005; 4: Kumarappan 2009 (Canada Data Only).*

9. Existing Generators

9.1. Existing Generator Data

Existing generators within the United States portion of WECC are geolocated into load areas using Ventyx EV Energy Map (Ventyx EV Energy Map 2009). Generators found in the United States Energy Information Agency's Annual Electric Generator Report (United States Energy Information Agency 2007a) but not in the Ventyx EV Energy Map database are geolocated by ZIP code. Canadian and Mexican generators are included using data in WECC's Transmission Expansion Planning Policy Committee database of generators (Western Electricity Coordinating Council 2009). Generators with the primary fuel of coal, natural gas, fuel oil, nuclear, water (hydroelectric, including pumped storage), geothermal, biomass solid, biomass liquid, biogas and wind are included. Existing synthetic crude oil, solar thermal, and solar photovoltaic generators, as well as biomass co-firing units on existing coal plants are not included in the current version of the model. These generators constitute less than 2% of the existing generating capacity in WECC.

Existing generators are assumed to use the fuel with which they generated the most electricity in 2007 as reported in the United States Energy Information Agency's Form 906 (United States Energy Information Agency 2007b). Generator-specific heat rates are derived by dividing each generator's fuel consumption by its total electricity output in 2007. Canadian and Mexican plants are assigned the heat rates given to their technology class (Western Electricity Coordinating Council 2009), except for cogeneration plants, which are assigned the average heat rate for United Stated generators with the same fuel and prime mover.

Capital and operating costs for existing coal and hydroelectric generators originate from present day costs found in the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010a). Costs for non-coal, non-hydroelectric generators originate from the California Energy Commission's Cost of Generation Model (California Energy Commission 2010). To reflect shared infrastructure costs, cogeneration plants are assumed to have 75% of the capital cost of pure electric plants. Capital costs of existing plants are included as sunk costs and therefore do not influence decision variables.

Existing plants are not allowed to operate past their expected lifetime with the exception of nuclear plants, which are given the choice to continue plant operation by paying all operational costs in investment periods past the expected lifetime of the plant in question.

In order to reduce the number of decision variables, non-hydroelectric generators are aggregated by prime mover for each plant and hydroelectric generators are aggregated by load area.

9.2. Existing Hydroelectric and Pumped Hydroelectric Plants

Hydroelectric and pumped hydroelectric generators include constraints derived from historical monthly generation data from 2006. For non-pumped hydroelectric generators in the United States, monthly net generation data from the United States Energy Information Agency's Form 906 (United States Energy Information Agency 2007b) is employed. The profile of Washington and Montana monthly net generation data is used to shape British Columbia and Albertan hydroelectric generation, respectively. Hydroelectric and pumped hydroelectric generators are aggregated to the load area level in order to reduce the number of decision variables.

For pumped hydroelectric generators, the use of net generation data is not sufficient, as it takes into account both electricity generated from in-stream flows and efficiency losses from the pumping process. The total electricity input to each pumped hydroelectric generator (United States Energy Information Agency 2007b) is used to correct this factor. By assuming a 74% round-trip efficiency (Electricity Storage Association 2010) and that monthly in-stream flows for pumped hydroelectric projects are similar to those from non-pumped projects, the monthly in-stream flow for pumped projects is derived. No pumped hydroelectric plants currently exist in Canadian or Mexican WECC territory (Ventyx EV Energy Map 2009).

New hydroelectric facilities are not built in the current version of the model. The high capital cost of these generators, especially pumped storage, would likely preclude installation.

9.3. Existing Wind Plants

Hourly existing wind farm power output is derived from the 3TIER Western Wind and Solar Integration Study (WWSIS) wind speed dataset (3TIER 2010; GE Energy 2010) using idealized turbine power output curves on interpolated wind speed values. The total capacity, number of

turbines, and installation year of each wind farm in the United States that currently exists or is under construction is obtained from the American Wind Energy Association (AWEA) wind plant dataset (American Wind Energy Association 2010). The total existing wind farm capacity in WECC is 10 GW. Wind farms are geolocated by matching wind farms in the AWEA dataset with wind farms in the Ventyx EV Energy Map dataset (Ventyx EV Energy Map 2009). Existing Canadian wind farms are not currently included in the model. At present, the Mexican portion of WECC does not have operational utility-scale wind turbines (The Wind Power 2010).

Historical production from existing wind farms could not be used as many of these wind projects began operation after the historical study year of 2006. In addition, historical output would include forced outages, a phenomenon that is factored out of hourly power output in SWITCH.

In order to calculate hourly capacity factors for existing wind farms, the rated capacity of each wind turbine is used to find the turbine hub height and rotor diameter using averages by rated capacity from 'The Wind Power' wind turbines and wind farms database (The Wind Power 2010). Wind speeds are interpolated from wind points found in the 3TIER wind dataset (3TIER 2010) to the wind farm location using an inverse distance-weighted interpolation. The resultant speeds are scaled to turbine hub height using a friction coefficient of 1/7 (Masters 2004). These wind speeds are put through an ideal turbine power output curve (Westergaard 2009) to generate the hourly power output for each wind farm in the WECC.

10. New Generators

10.1. Capital and O&M Costs

The present day capital costs and operation and maintenance (O&M) costs for each power plant type originate primarily from the California Energy Commission Cost of Generation Model (California Energy Commission 2010). Present day costs for coal and carbon capture and sequestration generation originate from the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b). Costs for photovoltaic generators originate from the National Renewable Energy Laboratory's Solar Vision Study (United States Department of Energy 2010). Captial costs in SWITCH decrease over time via exponential decay using decay rates derived from (Black & Veatch 2010). O&M costs are assumed to remain constant over time.

Fuel	Technology	Overnight Cost in 2011 [$2007/W]	Overnight Cost Change [%/yr]	Fixed O&M [$2007/MW*yr]	Variable O&M [$2007/MWh]	Efficiency [%]	Carbon Emissions [tCO$_2$/MWh]
Bio Gas	Bio Gas	2.28	-1.44	114000	0.01	25	0
Bio Gas CCS	Bio Gas CCS	4.17	-1.94	156000	13.77	18.9	-1.633
Bio Solid	Biomass IGCC	2.7	-1.48	140000	3.71	32.5	0
Bio Solid CCS	Biomass IGCC CCS	4.61	-1.70	158000	5	26.4	-1.036
Coal	Coal Steam Turbine	2.57	-1.19	27000	3.89	38.8	0.841
Coal	Coal IGCC	2.91	-1.48	45000	6.29	39.2	0.831
Coal CCS	Coal Steam Turbine CCS	4.14	-1.37	58000	8.29	28.4	0.172
Coal CCS	Coal IGCC CCS	4.82	-1.70	63000	7.37	31.9	0.153
Gas	Gas Combustion Turbine	0.75	-1.35	15000	3.4	39.9	0.454
Gas	Compressed Air Energy Storage	1.1	-0.12	9000	2.84	77.6*	0.233
Gas	CCGT	0.9	-1.35	7000	2.46	52.8	0.343
Gas CCS	CCGT CCS	1.85	-1.82	28000	5.73	45.4	0.06
Gas CCS	Gas Combustion Turbine CCS	1.7	-1.94	36000	7.71	34.3	0.079
Geothermal	Geothermal	3.69	-1.00	44000	3.17		0
Solar	Central PV	3.63	-3.73	10000	0		0
Solar	Commercial PV	4.53	-4.57	10000	0		0
Solar	CSP Trough 6h Storage	5.74	-0.89	63000	0		0
Solar	Residential PV	5.27	-4.85	10000	0		0
Solar	CSP Trough No Storage	3.37	-0.89	63000	0		0
Storage	Battery Storage	4.11	-0.56	26000	0.52		0
Uranium	Nuclear	3.67	0.00	137000	4.82	32.8	0
Wind	Offshore Wind	5.06	-1.30	25000	9.47		0
Wind	Wind	1.83	-0.05	13000	4.73		0

Appendix Table 2: *New generator costs, heat rates and outage rates. The base overnight cost shown here represents the overnight cost incurred when starting construction in 2011. *The efficiency of Compressed Air Energy Storage quoted here contains only the natural gas part of energy generation – energy from the compressed air in the storage cavern is also needed, lowering the total efficiency.*
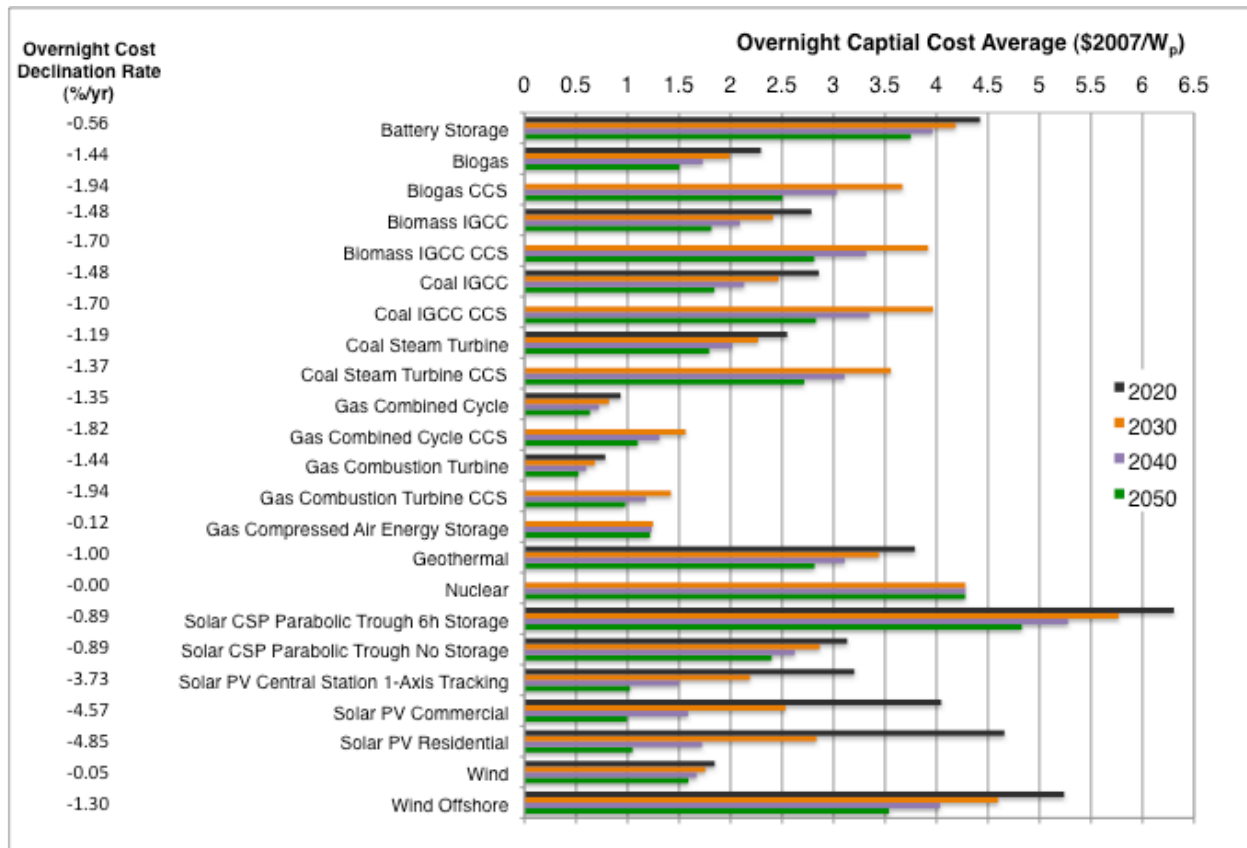
Appendix Figure 2: *Average generator and storage overnight capital costs in each investment period. Plants not eligible for construction in the 2020 investment period are excluded from this chart. The costs shown do not include expenses related to project development such as interest during construction, connection costs to the grid and upgrades to the local grid, though these costs are included in each optimization.*

10.2. Connection Costs

The cost to connect new generators to the existing electricity grid is derived from the United States Energy Information Agency's 2007 Annual Electric Generator Report (United States Energy Information Agency 2007a). Connection costs for different technologies are shown in Supplemental Table 4 below.

The generic connection cost category applies to projects that *are not* sited at specific geographic locations in SWITCH. For these projects, it is assumed that it is possible to find a project site near existing transmission in each load area, thereby not incurring significant costs to build new transmission lines to the grid. The average cost over the United States in 2007 to connect generators to the grid without a large transmission line was $91,289 per MW (United States Energy Information Agency 2007a). Substation installation or upgrade and grid enhancement costs that are incurred by adding the generator to the grid account for $65,639 per MW of the total connection cost. Constructing a small transmission line to the existing grid accounts for $25,650 per MW of the total connection cost.

The site-specific connection cost category applies to projects that *are* sited in specific geographic locations but are not considered distributed generation in SWITCH. For these projects, the calculated cost to build a transmission line from the resource site to the nearest substation at or above 115 kV replaces the cost to build a small transmission line above. The cost to build this new line is $1,000 per MW per km, the same as to the assumed cost of building transmission between load areas. Underwater transmission for offshore wind projects is assumed to be five times this cost, $5000 per MW per km. The load area of each site-specific project is determined through connection to the nearest substation, as the grid connection point represents the part of the grid into which these projects will inject power.

Generic	Site Specific	Distributed
$91,289/MW ($2007)	$65,639/MW ($2007)	$0/MW ($2007)
No Additional Transmission	Additional Distance-Specific Transmission Costs Incurred	Interconnection Included In Capital Cost
Nuclear	Wind	Residential Photovoltaic
Gas Combined Cycle	Offshore Wind	Commercial Photovoltaic
Gas Combustion Turbine	Central Station Photovoltaic	
Coal Steam Turbine	Solar Thermal Trough, No Thermal Storage	
Coal Integrated Gasification Combined Cycle	Solar Thermal Trough, 6h Thermal Storage	
Biomass Integrated Gasification Combined Cycle		
Biogas		
Battery Storage		
Compressed Air Energy Storage		

Appendix Table 3: *Connection Cost Types in SWITCH. As these costs represent costs to connect a generator to the electricity grid, they are the same per unit of capacity for generation with or without cogeneration and/or carbon capture and sequestration.*

The distributed connection cost category currently applies only to residential and commercial photovoltaic projects. For these projects, the interconnection costs are included in project capital costs and are therefore not explicitly specified in other parts of the model.

The connection cost of existing generators is assumed to be included in the capital costs of each existing plant.

10.3. Non-Renewable Thermal Generators

10.3.1. Non-Renewable Non-CCS Thermal Generators

Nuclear steam turbines, coal steam turbines, and coal integrated gasification combined cycle plants (Coal IGCC) are modeled as baseload technologies. Their output remains constant in every study hour, de-rated by their forced and scheduled outage rates. These technologies are assumed to be buildable in any load area, which the exception of California load areas due to legal build restrictions on new nuclear and coal generation in California.

Natural gas combined cycle plants and combustion turbines are modeled as dispatchable technologies. The optimization chooses how much to dispatch from these generators in each study hour, limited by their installed capacity and de-rated by their forced outage rate. All thermal technologies in SWITCH have a fixed heat rate throughout all investment periods (see Supplemental Table 2).

All existing cogeneration plants are given the option to continue operation indefinitely at the existing plant's capacity, efficiency and cost. New cogeneration plants are not allowed to be installed in the current version of the model.

10.3.2. Non-Renewable Thermal Generators Equipped with Carbon Capture and Sequestration (CCS)

Generators equipped with carbon capture and sequestration (CCS) equipment are modeled similarlyto their non-CCS counterparts, but with different capital, fixed O&M and variable O&M costs, as well as different power conversion efficiencies. Newly installable non-renewable CCS technologies are: Gas Combined Cycle, Gas Combustion Turbine, Coal Steam Turbine, Coal Integrated Gasification Combined Cycle. In addition, all carbon-emitting existing cogeneration plants are given the option to replace the existing plant's turbine at the end of the turbine's operational lifetime with a new turbine of the same type equipped with CCS.

Costs for Gas Combined Cycle, Coal Steam Turbine and Coal Integrated Gasification Combined Cycle generators with CCS are used directly from the United States Energy Information Agency's Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b). In order to account for the additional cost of installing a CCS system into types of power plants for which consistent and up-to-date CCS cost data is not readily available, the capital cost difference between non-CCS and CCS generators with the same primemover is added to the capital cost of the non-CCS generator. For example, the capital cost of Gas Combustion Turbine CCS is assumed to be equal to the capital cost of non-CCS Gas Combustion Turbine plus the

difference in capital costs between Gas Combined Cycle and Gas Combined Cycle CCS (all values in units of \$/W). The same method is used for fixed O&M costs. As is the case with non-CCS cogeneration technologies, CCS cogeneration plants incur 75 % of the capital cost of non-cogeneration plants to reflect shared infrastructure costs. Variable O&M costs for CCS generators increase relative to their non-CCS counterparts from costs incurred during O&M of the CCS equipment itself, as well as costs incurred from the decrease in efficiency of CCS power plants relative to non-CCS plants. Costs input into the model can be found in the table of generator costs and efficiencies above.

Large-scale deployment of CCS pipelines would require large interconnected pipeline networks from CO_2 sources to CO_2 sinks. While the cost of construction of short pipelines is included in the Updated Capital Cost Estimates for Electricity Generation Plants (United States Energy Information Agency 2010b), CCS generators that are not near a CO_2 sink would be forced to build longer pipelines, thereby incurring extra capital cost. If a load area does not does not contain an adequate CO_2 sink (National Energy Technology Laboratory, 2008) within its boundaries, a pipeline between the largest substation in that load area and the nearest CO_2 sink is built, incurring costs consistent with those found in Middleton et al., 2009.

CCS technology is in its infancy, with a handful of demonstration projects completed to date. This technology is therefore not allowed to be installed in the 2015-2025 investment period, as gigawatt scale deployment would not be feasible in this timeframe. Starting in 2025, CCS generation can be installed in unlimited quantities (except for bio projects that are limited by the amount of available biofuel).

10.4. Compressed Air Energy Storage

Conventional gas turbines expend much of their gross energy compressing the air/fuel mixture for the turbine intake. Compressed air energy storage (CAES) works in conjunction with a gas turbine, using underground reservoirs to store compressed air for the intake. During off-peak hours, CAES uses electricity from the grid to compress air. During peak hours, CAES adds natural gas to the compressed air and releases the mixture into the intake of a gas turbine. CAES projects in the WECC version of SWITCH are cited in aquifer geology. Geospatial aquifer layers are obtained from the United States Geological Survey (United States Geological Survey 2003) and all sandstone, carbonate, igneous, metamorphic, and unconsolidated sand and gravel aquifers are included (Succar and Williams 2008; Electric Power Research Institute 2003). A density of 83 MW/km^2 is assumed, following (Succar and Williams 2008), resulting in nearly unlimited CAES potential in almost all load areas.

A storage efficiency of 81.7% is used, in concert with a round trip efficiency of 1.4 (Succar and Williams 2008) to apportion generation between renewable and non-renewable fuel categories when RPS is enabled, as natural gas is burned in addition to the input electricity from the grid. In addition, a compressor to expander ratio of 1.2 (Greenblatt *et al.* 2007) is assumed.

10.5. Battery Storage

Sodium sulfur (NaS) batteries are modeled using performance data from (Electric Power Research Institute 2002) for load-leveling batteries. Storage is modeled using a daily energy balance – it is therefore assumed that NaS batteries have sufficient energy capacity to provide daily load-leveling. An AC-DC-AC storage efficiency of 76.7 % is used. NaS battery storage is available for construction in all load areas and investment periods.

10.6. Geothermal

New sites for geothermal steam turbine power projects are compiled from two separate datasets of geothermal projects under consideration from power plant developers (Ventyx EV Energy Map 2009, Western Governors' Association 2009b). The larger potential capacity of projects appearing in both datasets is taken. As new geothermal projects are located at specific sites within a load area, they incur the cost of building a transmission line to the existing electricity grid rather than a generic connection costs. These projects represent 7 GW of new geothermal capacity potential.

10.7. Biogas and Biomass Solid

County-level biogas availability (Milbrandt 2005) is divided into load areas by the fraction of land area overlap of each county in each load area. This resource includes landfill gas, methane from wastewater treatment plants and methane from manure. Canadian and Mexican biogas resource potentials are scaled from United States potentials by population and Gross Domestic Product (GDP). Biogas plants are not sited in specific geographic locations within each load area and therefore incur the generic connection cost for connection to the existing electricity. It is assumed that new biogas plants will use combustion turbine technology.

New biomass solid generation is assumed to use integrated gasification combined cycle technology. Installation of biomass solid generation is constrained by the resource availability if biomass solid fuel in each load area.

New biogas and biomass solid combined heat and power units (cogenerators) can be installed to replace existing plants, but cannot be expanded beyond the existing cogeneration potential.

CCS biogas generation is included in all scenarios discussed in this report, while biomass solid integrated gasification combined cycle generation is only available in the Biomass CCS scenario. Sequestration of biomass solid and biogas is modeled as carbon negative with 85% carbon capture efficiency. Biogas CCS is assumed to capture both pre- and post-combustion CO_2 (biogas is typically ~1:1 CH_4:CO_2).

10.8. Wind and Offshore Wind Resources

Hourly wind turbine output was obtained from the 3TIER wind power output dataset produced for the Western Wind and Solar Integration Study (WWSIS) (3TIER 2010). 3TIER modeled the historical 10-minute power output from Vestas V-90 3-MW turbines in a 2-km by 2-km

grid cells across the western United States over the years 2004-2006 using the Weather Research and Forecasting (WRF) mesoscale weather model. Each of these grid cells was found to contain ten turbines, so each grid cell represents 30 MW of potential wind capacity. The Vestas V-90 3-MW turbine has a 100 m hub height.

Grid cells that were selected by the following criteria to create a final dataset of 32,043 wind points:

1) Wind projects that already exist or are under development
2) Sites with the high wind energy density at 100 m within 80 km of existing or planned transmission networks
3) Sites with high degree of temporal correlation to load profiles near the grid point
4) Sites with the highest wind energy density at 100 m (irrespective of location)

All of the wind points within WECC are aggregated into 3,362 wind farms. Many of the wind points were very near each other; adjacent wind points are aggregated if their area is within the corner-to-corner distance of each other, 2.8 km. Wind points with standard deviations in their average SCORE-lite power output (3TIER 2010) greater than 3 MW are aggregated into different wind farms. Offshore and onshore wind points are aggregated separately. The 10-minute SCORE-lite power output for each wind point is averaged over the hour before each timestamp, and then these hourly averages are again averaged over each group of aggregated wind points to create the hourly output of 3,314 onshore (875 GW) and 48 offshore (6 GW) wind farms.

Canadian hourly wind data will be integrated into future versions of the model.

10.9. Solar Resources

10.9.1. Weather file creation

Hourly weather and insolation files in the standard typical meteorological year 2 (TMY2) format for 41,000 sites for the historical years 2004 and 2005 were created by merging 10km-resolution gridded satellite insolation data from the State University of New York (SUNY) (Perez *et al.* 2002; National Renewable Energy Laboratory 2010b) and ~38km-resolution data from the National Center for Environmental Prediction's (NCEP) Climate Forecast System Reanalysis (CFSR) (Saha *et al.* 2010; National Climatic Data Center 2010).

The CFSR data are modified using standard approximations to conform to the TMY2 format. Wind velocity as reported by CFSR is at height of 10 meters – to convert to the TMY2 height of 2 meters, the friction coefficient of 1/7 is used (Masters 2004). Snow water equivalent is converted to snow depth using a 0.1 density conversion factor (Saha *et al.* 2010). Specific humidity is converted to relative humidity (Holton, Pyle, and Curry 2003) and the dew temperature is calculated (National Oceanic and Atmospheric Administration 2009). Wet bulb temperature is estimated from dry bulb temperature using the "1/3 rule" (Haby n.d.).

Time-shifted SUNY gridded insolation data as downloaded from the National Solar Radiation Database (National Renewable Energy Laboratory 2010b) was modified due to an error in time-shifting the direct normal insolation (DNI) values for a fraction of the sunset hours. In these hours, representing 0.1% of the hours, the DNI on a horizontal surface significantly exceeds the largest possible value of clear sky insolation, taking into account the air mass present at each grid cell (Meinel and Meinel 1976) and solar incidence angles (Duffie and Beckman 2006). When the

SUNY value for DNI exceeded the largest possible value by more than 100 Wm^{-2}, the largest possible DNI value was used instead of the SUNY value. SUNY values for the diffuse and global radiation did not to have this problem, and as such were left unmodified.

The CFSR weather grid was combined with the SUNY grid by finding the CFSR grid cell centroid nearest to each SUNY grid cell centroid. For coastal SUNY grid cells, the centroid of the nearest land-based CFSR grid cell was used, as weather conditions change rapidly on the ocean-land boundary and all modeled solar projects are on land.

The weather files are used as inputs to the National Renewable Energy Laboratory's Solar Advisor Model (National Renewable Energy Laboratory 2010a) to calculate the simulated historical output of various types of solar projects.

10.9.2. Distributed Photovoltaics – Residential and Commercial

Residential and Commercial photovoltaic sites were chosen by overlaying a United States raster layer of population density with the SUNY grid cells and selecting any grid cell with a total population greater than 10,000 in the year 2000. Mexican and Canadian cities in WECC with a population greater than 10,000 were included if they were located within the SUNY insolation grid. This includes most major Mexican population centers in Baja California Norte, as well as many of the southern Canadian cities in WECC. This process produced 920 individual SUNY grid cells to simulate residential and commercial photovoltaic systems in WECC. These cells were aggregated to 222 sites by joining adjacent grid cells such that the standard deviation of average global horizontal radiation values within each aggregated site is less than 0.1 kWh/m^2/day. This is accomplished by sequestering grid cells with greater than +/- 0.2 kWh/m^2/day from the average global horizontal radiation value within each aggregated area into a smaller aggregated area.

In SAM, residential, commercial and central station photovoltaic systems are simulated using the California Energy Commission module model as 270 W multi-crystalline silicon Suntech STP270-24-Vb-1 modules.

For residential photovolatics, these modules are connected in a 10-module string to make a 2.7 kW array and are coupled with a 3 kW SMA America SB3000US 208 V inverter. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid derating factor is assumed to be 89%.

Commercial photovoltaic systems are simulated as a 100 kW array with a single point efficiency inverter at 95% efficiency and a DC capacity of 105 kW. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid de-rating factor is assumed to be 91%.

The roof area available for distributed photovoltaic development is estimated based on Navigant (Chaudhari, Frantzis, and Hoff 2004) and NREL (Denholm and Margolis 2007) reports. State-level roof area data (Chaudhari, Frantzis, and Hoff 2004) projected to 2025 is apportioned to load areas by population fraction. Twenty percent of all residential and 60% of all commercial roof area is assumed to be available for development. The rooftop spacing ratio for commercial photovoltaics is derived from the Department of Defense Unified Facilities Criteria (United States Department of Defense 2002). Canadian rooftop availability is assumed to be similar to that of the nearest U.S. state. Baja California Norte rooftop availability is scaled by GDP from California values. In total, 117 GW of residential and 88 GW of commercial photovoltaics are included.

Land suitable for large-scale solar development is derived using land exclusion criteria from Mehos and Perez (2005), but without a minimum insolation cutoff. Types of land excluded are: national parks, monuments, wildlife refuges, military land, urban areas, land with greater than 1% slope (at 1 km resolution), and parcels of land smaller than 1 km^2. In addition, only areas with land cover of wooded and non-wooded grassland, closed and open shrubland, and bare ground are assumed to be available for solar development.

The available solar land is aggregated on the basis of average global insolation and DNI. An iterative procedure that partitions available solar land polygons with standard deviations of greater than 0.05 kWh/m^2/day average global insolation or DNI into smaller polygons is employed to create the final solar farms.

In SAM, central station photovoltaics are modeled as 100 MW (AC) arrays using the same mulitcrystalline panels discussed above and mounted on a single axis tracker. The array is connected to a single point efficiency inverter with 95% efficiency. The tracker is modeled using SunPower specifications (SunPower Corporation 2009), and as such is southward facing at a 20° tilt on a one-axis tracker, with ground coverage ratios of 0.20 at low latitudes, increasing to 0.24 at high latitudes. A de-rating factor of 90% is used to convert from power produced at the module to power available to the grid. A total of 15 TW of central station photovoltaic systems are simulated; after site selection (see Section III.10.8.4) this is reduced to 4 TW.

CSP systems without thermal storage are modeled in SAM using the 'Physical Trough' model for CSP parabolic trough systems. In total, 100 MW nameplate systems using Solargenix SGX-1 collectors in an 'H' configuration with an evaporative cooling system are modeled with a total field aperture area calculated by minimizing the total levelized cost of energy with respect to aperture area. Costs for CSP systems are scaled to this aperture area from the base cost values. A total of 15 TW of CSP trough systems without storage are simulated; after site selection, this is reduced to 5 TW.

In the future, CSP trough systems with thermal storage will be simulated as above, but a bug in the storage dispatch of the latest available version of SAM makes this method impossible at present. Rather, the hourly output of 125 CSP trough sites (representing 272 GW of capacity) with six hours of thermal storage was obtained from the National Renewable Energy Laboratory. Dispatch of CSP storage is embedded in the hourly capacity factors – it is an input parameter rather than a variable.

10.10. Site Selection of Intermittent Projects

To decrease runtime, the number of solar and wind sites is reduced using criteria that retain the best quality resources, geographic diversity, and load-serving capability of each resource.
1) All sites with capacity factors that are at least 75% of the average capacity factor for their technology are included.
2) If more than five sites for the same technology are present in a load area, at least 10 of the highest average capacity factor projects are also retained.
3) Projects were selected such that the average generation (the capacity factor multiplied by

the resource potential) of a technology, where sufficient resources exist, must be greater than or equal to three times the average 2010 load in each load area.

These criteria primarily filter out onshore wind, as well as central station photovoltaic and solar thermal sites, for which there is enormous potential in WECC. All distributed photovoltaic and offshore wind sites are retained.

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